U.S. DISTRICT COURT
NORTHERN DISTRICT OF TEXAS
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Deputy

IN THE UNITED STATES DISTRICT COURT
FOR THE NORTHERN DISTRICT OF TEXAS
DALLAS DIVISION

HALLIBURTON ENERGY SERVICES, INC.,

Plaintiff,

v.

WEATHERFORD INTERNATIONAL, INC. and BJ SERVICES COMPANY,

Defendants.

CIVIL ACTION NO. 3-02CV1347-P

JURY TRIAL DEMANDED

ORIGINAL COMPLAINT

Plaintiff Halliburton Energy Services, Inc. alleges:

1. Plaintiff Halliburton Energy Services, Inc. ("Halliburton") is a Delaware corporation having a place of business located in Dallas County at 2601 E. Beltline Road, Carrollton, Texas 75006.

2. Upon information and belief, Defendant Weatherford International, Inc. ("Weatherford") is a Delaware corporation and is doing business in this district at several locations, including 2995 LBJ Freeway, Suite 186E, Dallas, Texas.

3. Upon information and belief, Defendant BJ Services Company ("BJ") is a Delaware corporation and is doing business in this district at several locations, including The Plaza of the Americas, 600 N. Pearl, Suite 2320, Dallas, Texas.

4. This action arises under the patent laws of the United States, Title 35 U.S.C. § 101, et seq. This Court has jurisdiction under Title 28 U.S.C. §§ 1331 and 1338(a). Venue for Defendants Weatherford and BJ exists in this district under Title 28 U.S.C. §§ 1391(b) and (c),

and 1400(b). Jurisdiction over each of the Defendants comports with the United States Constitution.

Patents In Suit

5. On December 21, 1993, United States Letters Patent No. 5,271,468 (the '468 patent) entitled "Downhole Tool Apparatus with Non-Metallic Components and Methods Of Drilling Thereof" was duly and legally issued to Plaintiff Halliburton (f/k/a Halliburton Company), a true and correct copy of which is attached hereto as Exhibit A.

6. On July 6, 1993, United States Letters Patent No. 5,224,540 (the '540 patent) entitled "Downhole Tool Apparatus with Non-Metallic Components and Methods of Drilling Thereof" was duly and legally issued to Plaintiff Halliburton (f/k/a Halliburton Company), a true and correct copy of which is attached hereto as Exhibit B.

7. At all times since the issuance of the '468 and '540 patents, Plaintiff Halliburton has been and still is the owner of each of these patents.

Patent Infringement

8. Defendant Weatherford has been and is making, using, selling, and offering to sell within the United States downhole well tool products identified by Defendant Weatherford as the "FracGuard Series Composite Bridge Plug" and the "FracGuard Series Composite Frac Plug." A true and correct copy of a page available on Defendant Weatherford's internet website relating to the "FracGuard Series Composite Bridge Plug" is attached hereto as Exhibit C, document number W000001. A true and correct copy of a page available on Defendant Weatherford's internet website relating to the "FracGuard Series Composite Frac Plug" is attached as Exhibit D, document number W000002.

9. Defendant BJ has been and is making, using, selling, and offering to sell within the United States downhole well tool products identified by Defendant BJ as its "Python Composite Bridge Plug." A true and correct copy of a page available on Defendant BJ's internet website relating to the "Python Composite Bridge Plug" is attached as Exhibit E, document number BJ000001. A true and correct copy of slides from a Power Point presentation available on Defendant BJ's internet website relating to the "Python Composite Bridge Plug" is attached as Exhibit F, document numbers BJ000004-25.

10. Both Defendants Weatherford and BJ have been and are infringing the '468 and '540 patents by making, using, selling, and offering to sell products (including those products referred to in paragraphs 8 and 9) and services embodying the patented inventions of at least claims 1, 2, 30-32, and 73 of the '468 patent and at least claims 1-5 of the '540 patent and by inducing and contributing to the infringement of the '468 and '540 patents by others.

11. Defendants Weatherford and BJ have been given notice in accordance with Title 35 U.S.C. § 287 regarding the '468 and '540 patents.

12. Since being given notice regarding the '468 and '540 patents, Defendants Weatherford and BJ have continued to infringe, induce the infringement, and contribute to the infringement of the '468 and '540 patents.

13. Defendants Weatherford and BJ have damaged Plaintiff Halliburton and are causing Plaintiff Halliburton irreparable harm.

14. Plaintiff Halliburton is entitled to recover damages from Defendants Weatherford and BJ as provided under Title 35 U.S.C. § 284.

15. Upon information and belief, Defendants Weatherford and BJ will continue to infringe the '468 and '540 patents unless enjoined by this Court.

16. Upon information and belief, the conduct of both Defendants Weatherford and BJ constitutes knowing and willful infringement of the '468 and '540 patents, such that Plaintiff Halliburton is entitled to an increase in the damages up to three times the amount found or assessed, as provided by Title 35 U.S.C. § 284.

17. Upon information and belief, the conduct of Defendants Weatherford and BJ presents an exceptional case such that Plaintiff Halliburton is entitled to an award of its reasonable attorney's fees, as provided by Title 35 U.S.C. § 285.

Demand for Jury Trial

18. Plaintiff Halliburton demands a jury trial on its claims.

Requested Relief

WHEREFORE, Plaintiff Halliburton requests that:

1. The Court enter judgment for Plaintiff Halliburton and against Defendants Weatherford and BJ for infringement of the '468 and '540 patents;

2. Defendants Weatherford and BJ, their subsidiaries, divisions, and affiliates, and their respective directors, officers, agents, servants, representatives, employees, customers, successors and assigns, and all persons in active concert or participation with any of them be temporarily restrained, preliminarily enjoined pending this action, and permanently enjoined from infringement of the '468 and '540 patents, in any manner;

3. Defendants Weatherford and BJ, their officers, directors, servants, employees, and attorneys be ordered to deliver up to Plaintiff Halliburton an accounting for damages for all infringements upon, directly or indirectly or otherwise, the '468 and '540 patents;

4. Defendants Weatherford and BJ be ordered to pay to Plaintiff Halliburton an amount of damages adequate to compensate Halliburton for their infringement of the '468 and '540 patents, as provided by Title 35 U.S.C. § 284;

5. Defendants Weatherford and BJ be ordered to pay to Plaintiff Halliburton increased damages up to three times the amount found or assessed against them for their infringement, as provided by Title 35 U.S.C. § 284;

6. Defendants Weatherford and BJ be ordered to pay Plaintiff Halliburton its reasonable attorney's fees incurred in this action, as provided by Title 35 U.S.C. § 285;

7. Defendants Weatherford and BJ be ordered to pay Plaintiff Halliburton its costs incurred in this action;

8. Defendants Weatherford and BJ be ordered to pay Plaintiff Halliburton pre-judgment and post-judgment interest for the damages awarded in this action; and

9. Plaintiff Halliburton be granted such other and further relief, as the Court may deem just and equitable.

Dated: 27 June 2002

Respectfully submitted,

John F. Booth, Texas Bar No. 00265000
Todd E. Albanesi, Texas Bar No. 00969162
David L. Joers, Texas Bar No. 10669800
Peter Schroeder, Texas Bar No. 00794606
Renée Skinner, Texas Bar No. 00791673

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Attorneys for Halliburton Energy Services, Inc.

The United States of America

The Commissioner of Patents and Trademarks

Has received an application for a patent for a new and useful invention. The title and description of the invention are enclosed. The requirements of law have been complied with, and it has been determined that a patent on the invention shall be granted under the law.

Therefore, this

United States Patent

Grants to the person or persons having title to this patent the right to exclude others from making, using or selling the invention throughout the United States of America for the term of seventeen years from the date of this patent, subject to the payment of maintenance fees as provided by law.

Bruce Lehman

Commissioner of Patents and Trademarks

Priscilla A Fuller

Attest

US005271468A

United States Patent [19]

Streich et al.

[11] Patent Number: 5,271,468

[45] Date of Patent: Dec. 21, 1993

[54] DOWNHOLE TOOL APPARATUS WITH NON-METALLIC COMPONENTS AND METHODS OF DRILLING THEREOF

[75] Inventors: Steven G. Streich; Donald F. Hushbeck; Kevin T. Berscheidt; Rick D. Jacobi, all of Duncan, Okla.

[73] Assignee: Halliburton Company, Duncan, Okla.

[21] Appl. No.: 719,740

[22] Filed: Jun. 21, 1991

Related U.S. Application Data

[63] Continuation-in-part of Ser. No. 515,019, Apr. 26, 1990, abandoned.

[51] Int. Cl.[5] E21B 33/129

[52] U.S. Cl. 166/387; 166/118; 166/134; 166/217; 166/376; 175/57

[58] Field of Search 166/376, 387, 118, 135, 166/134, 138, 179, 192, 382, 123, 128, 242; 175/57

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4,834,184	5/1989	Streich et al.	166/376
4,858,687	8/1989	Watson et al.	166/153
4,977,958	12/1990	Miller	166/205

OTHER PUBLICATIONS

Halliburton Sales & Service Catalog No. 43, published in 1985, pp. 2561-2562; 2556-2557; 2427-2434.

Halliburton Services Sales Technical Paper S-8107 entitled "Successful Drill Out Of Shoe Joints With PDC Bits", published in Mar., 1989.

Chapter 4, Fundamentals of Drilling, by John L. Kennedy, PennWell Books, Copyright 1983.

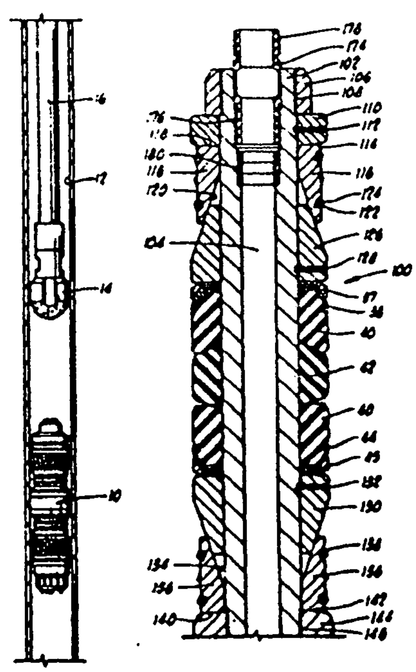
"Molding Compounds Materials Selection Handbook", published by Fiberite Corporation, Copyright, 1986.

Primary Examiner—Stephen J. Novosad

[57] ABSTRACT

A downhole tool apparatus and methods of drilling the apparatus. The apparatus may include, but is not limited to, packers and bridge plugs utilizing non-metallic components. The material may include engineering grade plastics. The nonmetallic components may include but are not limited to the center mandrel, slips, slip wedges, slip supports and housings, spacer rings, valve housings and valve components. Methods of drilling out the apparatus without significant variations in the drilling speed and weight applied to the drill bit may be employed. Alternative drill bit types, such as polycrystalline diamond compact (PDC) bits may also be used.

75 Claims, 6 Drawing Sheets



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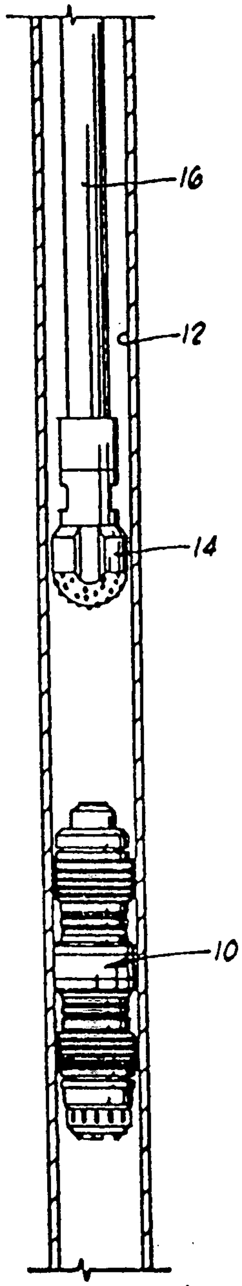
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FIG. 1

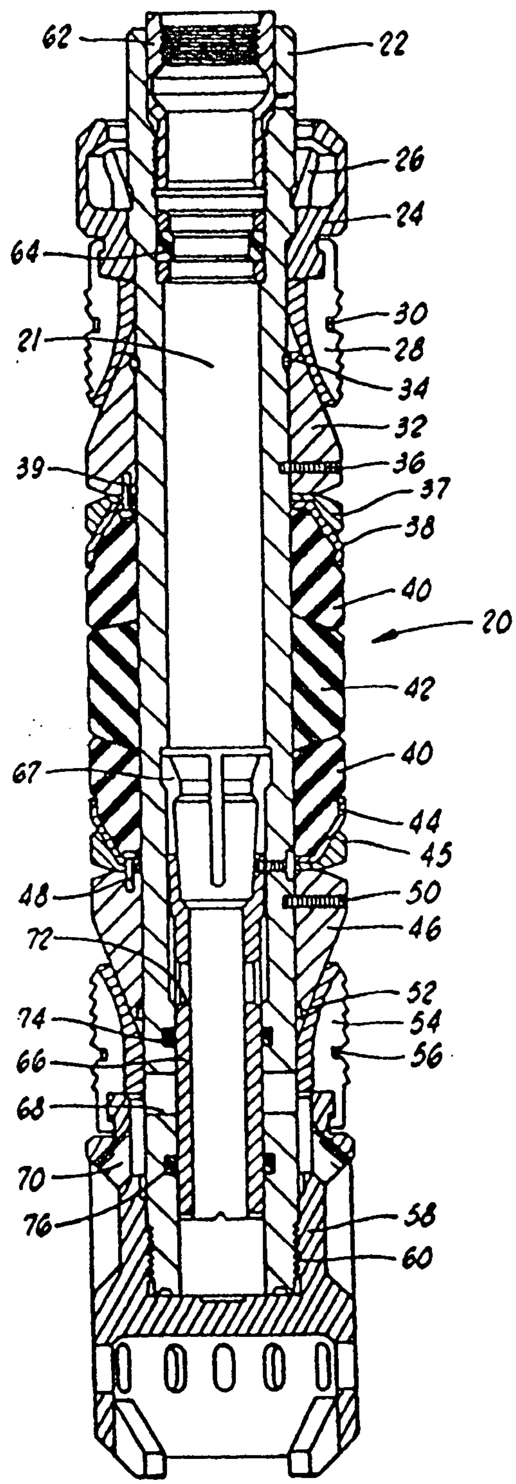
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FIG. 2

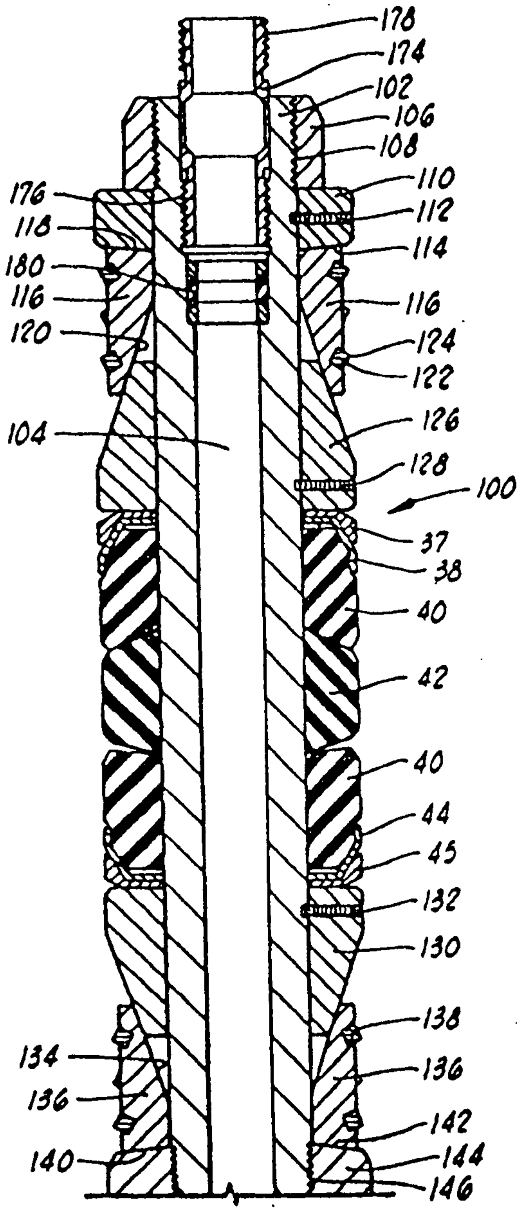
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FIG. 3A

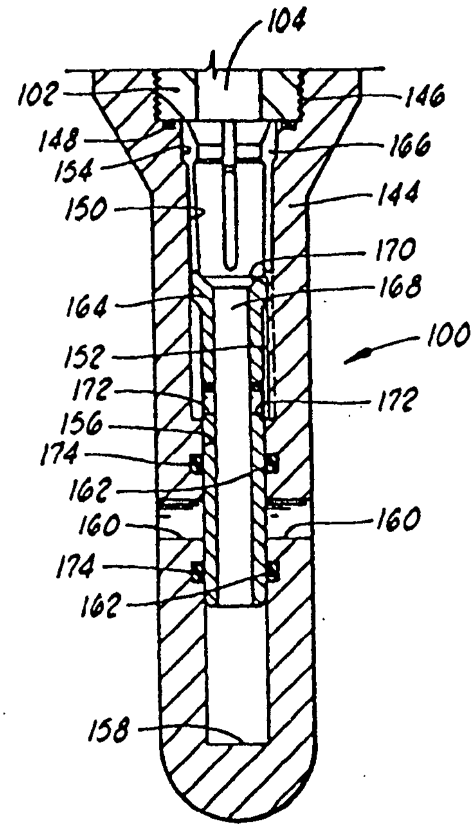
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FIG. 3B

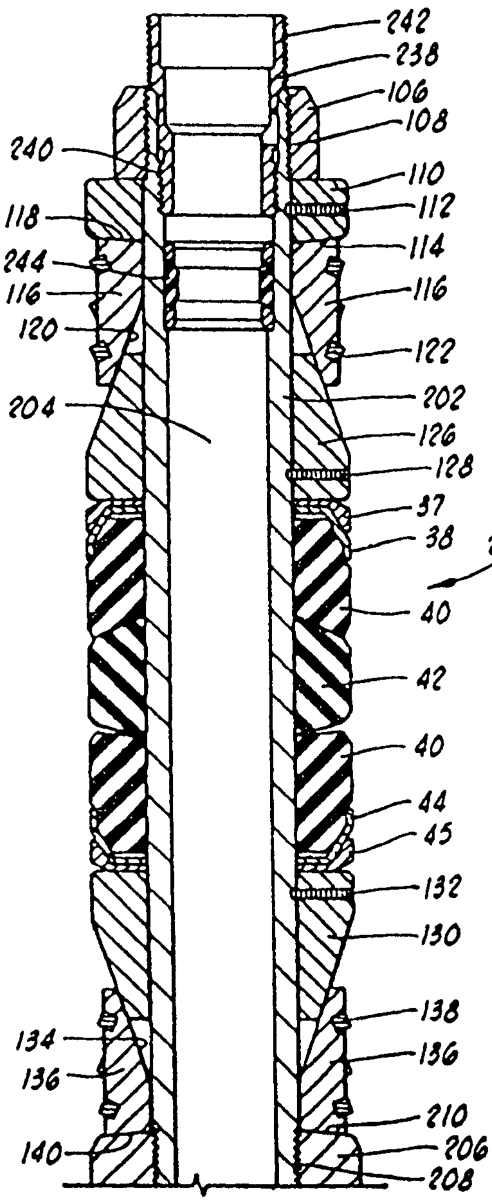
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FIG. 4A

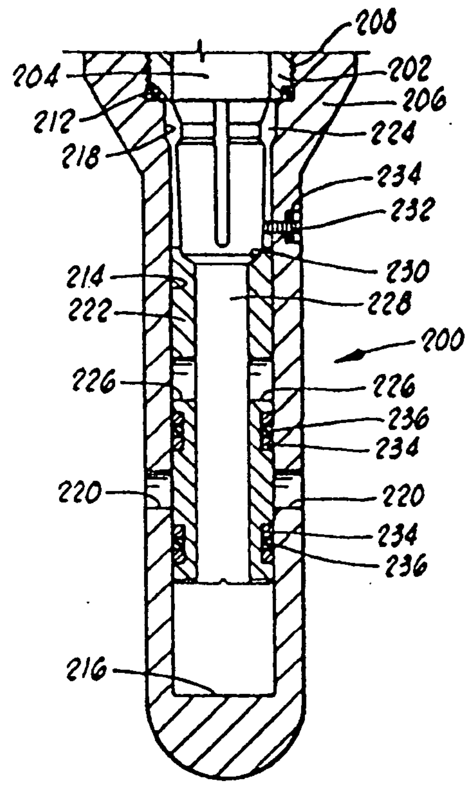
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FIG. 4B

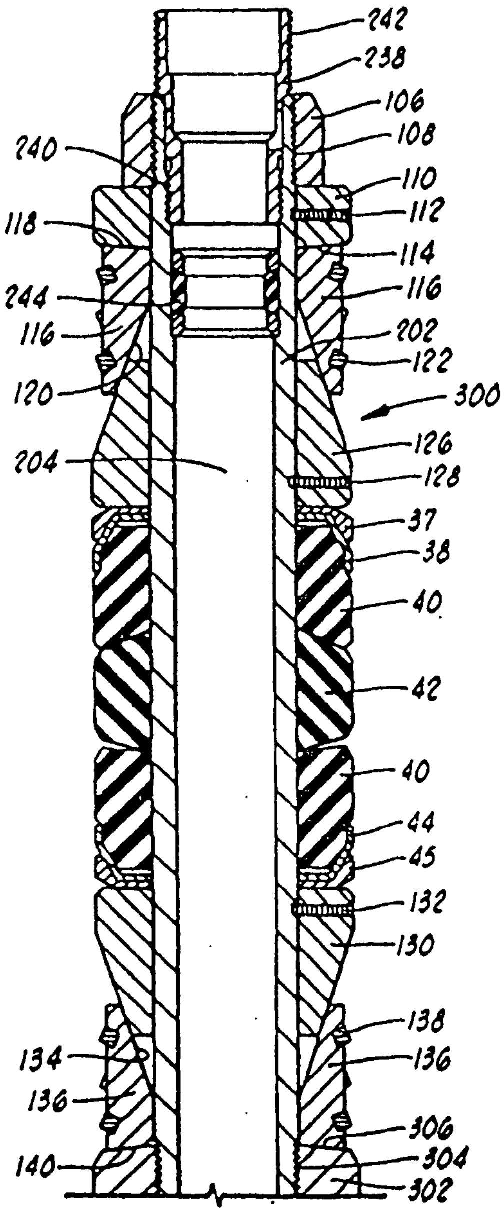
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FIG. 5A

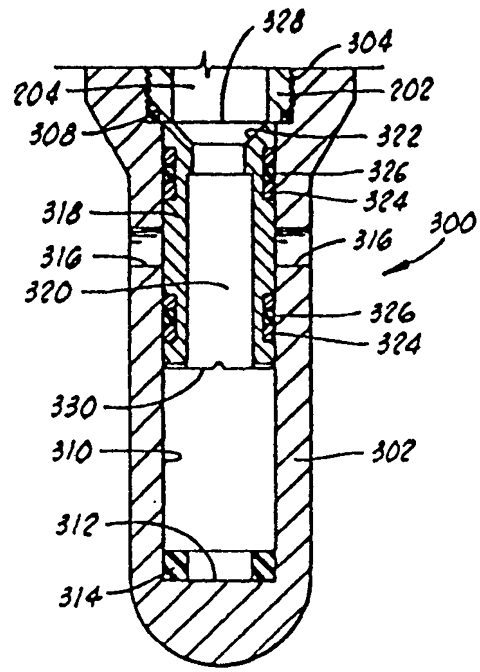
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FIG. 5B

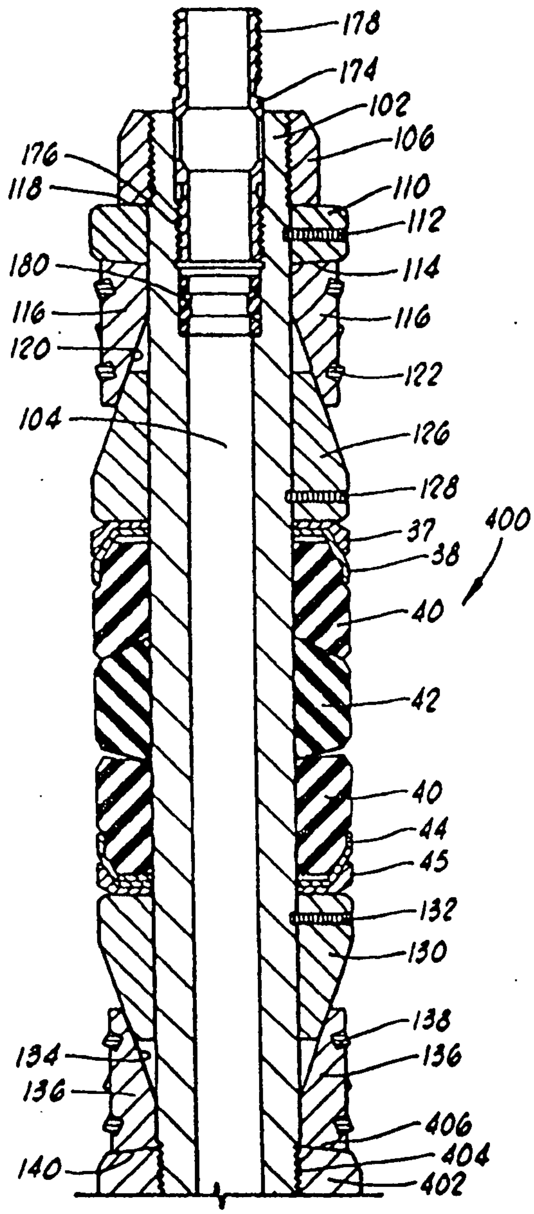
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FIG. 6A

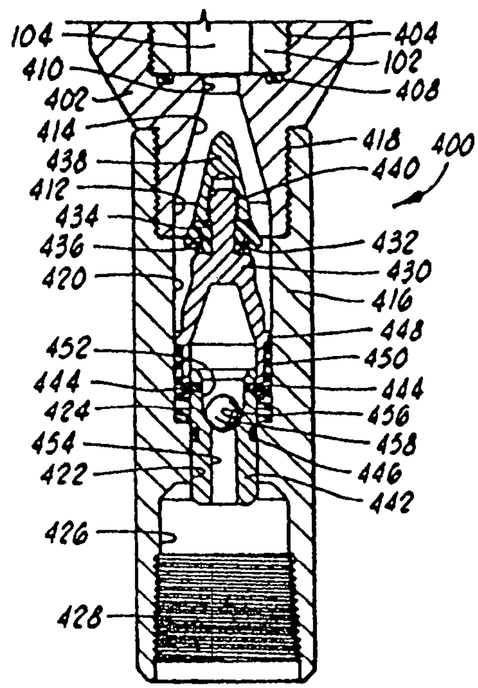
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FIG. 6B

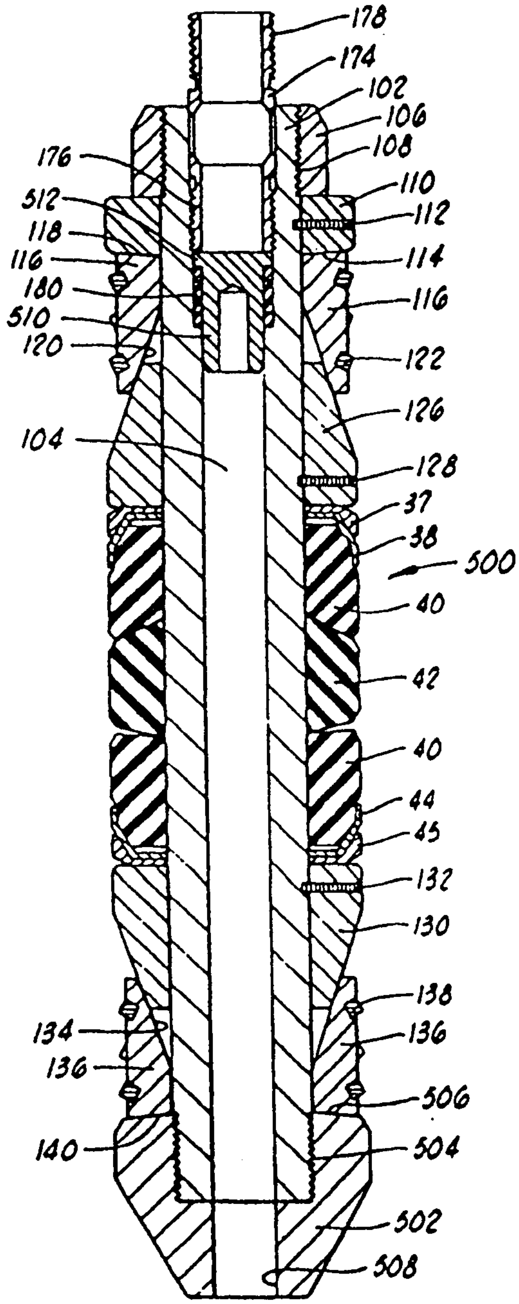
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FIG. 7

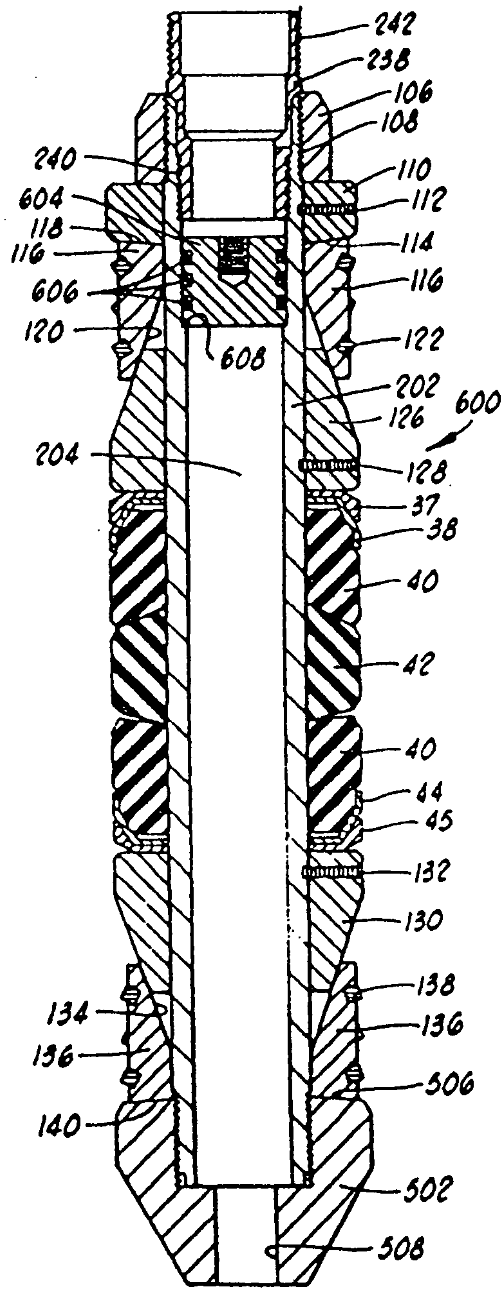
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FIG. 8

DOWNHOLE TOOL APPARATUS WITH NON-METALLIC COMPONENTS AND METHODS OF DRILLING THEREOF

This application is a continuation-in-part of co-pending application Ser. No. 07/515,019, filed Apr. 26, 1990 now abandoned.

BACKGROUND OF THE INVENTION

1. Field Of The Invention

This invention relates to downhole tools for use in well bores and methods of drilling such apparatus out of well bores, and more particularly, to such tools having drillable components therein made of non-metallic materials, such as engineering grade plastics.

2. Description Of The Prior Art

In the drilling or reworking of oil wells, a great variety of downhole tools are used. For example, but not by way of limitation, it is often desirable to seal tubing or other pipe in the casing of the well, such as when it is desired to pump cement or other slurry down tubing and force the slurry out into a formation. It then becomes necessary to seal the tubing with respect to the well casing and to prevent the fluid pressure of the slurry from lifting the tubing out of the well. Packers and bridge plugs designed for these general purposes are well known in the art.

When it is desired to remove many of these downhole tools from a well bore, it is frequently simpler and less expensive to mill or drill them out rather than to implement a complex retrieving operation. In milling, a milling cutter is used to grind the packer or plug, for example, or at least the outer components thereof, out of the well bore. Milling is a relatively slow process, but it can be used on packers or bridge plugs having relatively hard components such as erosion-resistant hard steel. One such packer is disclosed in U.S. Pat. No. 4,151,875 to Sullaway, assigned to the assignee of the present invention and sold under the trademark EZ Disposal packer. Other downhole tools in addition to packers and bridge plugs may also be drilled out.

In drilling, a drill bit is used to cut and grind up the components of the downhole tool to remove it from the well bore. This is a much faster operation than milling, but requires the tool to be made out of materials which can be accommodated by the drill bit. Typically, soft and medium hardness cast iron are used on the pressure bearing components, along with some brass and aluminum items. Packers of this type include the Halliburton EZ Drill ® and EZ Drill SV ® squeeze packers.

The EZ Drill SV ® squeeze packer, for example, includes a lock ring housing, upper slip wedge, lower slip wedge, and lower slip support made of soft cast iron. These components are mounted on a mandrel made of medium hardness cast iron. The EZ Drill ® squeeze packer is similarly constructed. The Halliburton EZ Drill ® bridge plug is also similar, except that it does not provide for fluid flow therethrough.

All of the above-mentioned packers are disclosed in Halliburton Services Sales and Service Catalog No. 43, pages 2561-2562, and the bridge plug is disclosed in the same catalog on pages 2556-2557.

The EZ Drill ® packer and bridge plug and the EZ Drill SV ® packer are designed for fast removal from the well bore by either rotary or cable tool drilling methods. Many of the components in these drillable packing devices are locked together to prevent their spinning while being drilled, and the harder slips are grooved so that they will be broken up in small pieces. Typically, standard "tri-cone" rotary drill bits are used which are rotated at speeds of about 75 to about 120 rpm. A load of about 5,000 to about 7,000 pounds of weight is applied to the bit for initial drilling and increased as necessary to drill out the remainder of the packer or bridge plug, depending upon its size. Drill collars may be used as required for weight and bit stabilization.

Such drillable devices have worked well and provide improved operating performance at relatively high temperatures and pressures. The packers and plug mentioned above are designed to withstand pressures of about 10,000 psi and temperatures of about 425° F. after being set in the well bore. Such pressures and temperatures require the cast iron components previously discussed.

However, drilling out iron components requires certain techniques. Ideally, the operator employs variations in rotary speed and bit weight to help break up the metal parts and reestablish bit penetration should bit penetration cease while drilling. A phenomenon known as "bit tracking" can occur, wherein the drill bit stays on one path and no longer cuts into the downhole tool. When this happens, it is necessary to pick up the bit above the drilling surface and rapidly recontact the bit with the packer or plug and apply weight while continuing rotation. This aids in breaking up the established bit pattern and helps to reestablish bit penetration. If this procedure is used, there are rarely problems. However, operators may not apply these techniques or even recognize when bit tracking has occurred. The result is that drilling times are greatly increased because the bit merely wears against the surface of the downhole tool rather than cutting into it to break it up.

While cast iron components may be necessary for the high pressures and temperatures for which they are designed, it has been determined that many wells experience pressures less than 10,000 psi and temperatures less than 425° F. This includes most wells cemented. In fact, in the majority of wells, the pressure is less than about 5,000 psi, and the temperature is less than about 250° F. Thus, the heavy duty metal construction of the previous downhole tools, such as the packers and bridge plugs described above, is not necessary for many applications, and if cast iron components can be eliminated or minimized, the potential drilling problems resulting from bit tracking might be avoided as well.

The downhole tool of the present invention solves this problem by providing an apparatus wherein at least some of the components, including pressure bearing components, are made of non-metallic materials, such as engineering grade plastics. Such plastic components are much more easily drilled than cast iron, and new drilling methods may be employed which use alternative drill bits such as polycrystalline diamond compact bits, or the like, rather than standard tri-cone bits.

SUMMARY OF THE INVENTION

The downhole tool apparatus of the present invention utilizes non-metallic materials, such as engineering grade plastics, to reduce weight, to reduce manufacturing time and labor, to improve performance through reducing frictional forces of sliding surfaces, to reduce costs and to improve drillability of the apparatus when drilling is required to remove the apparatus from the well bore. Primarily, in this disclosure, the downhole

tool is characterized by well bore packing apparatus, but it is not intended that the invention be limited to such packing devices. The non-metallic components in the downhole tool apparatus also allow the use of alternative drilling techniques to those previously known.

In packing apparatus embodiments of the present invention, the apparatus may utilize the same general geometric configuration of previously known drillable packers and bridge plugs while replacing at least some of the metal components with non-metallic materials which can still withstand the pressures and temperatures exposed thereto in many well bore applications. In other embodiments of the present invention, the apparatus may comprise specific design changes to accommodate the advantages of plastic materials and also to allow for the reduced strengths thereof compared to metal components.

In one embodiment of the downhole tool, the invention comprises a center mandrel and slip means disposed on the mandrel for grippingly engaging the well bore when in a set position. In packing embodiments, the apparatus further comprises a packing means disposed on the mandrel for sealingly engaging the well bore when in a set position.

The slip means may comprise a wedge engaging a plurality of slips with a slip support on the opposite side of the slips from the wedge. Any of the mandrel, slips, slip wedges or slip supports may be made of the non-metallic material, such as plastic. Specific plastics include nylon, phenolic materials and epoxy resins. The phenolic materials may further include any of Fiberite FM4056J, Fiberite FM4005 or Resinoid 1360. The plastic components may be molded or machined.

One preferred plastic material for at least some of these components is a glass reinforced phenolic resin having a tensile strength of about 18,000 psi and a compressive strength of about 40,000 psi, although the invention is not intended to be limited to this particular plastic or a plastic having these specific physical properties. The plastic materials are preferably selected such that the packing apparatus can withstand well pressures less than about 10,000 psi and temperatures less than about 425° F. In one preferred embodiment, but not by way of limitation, the plastic materials of the packing apparatus are selected such that the apparatus can withstand well pressures up to about 5,000 psi and temperatures up to about 250° F.

Most of the components of the slip means are subjected to substantially compressive loading when in a sealed operating position in the well bore, although some tensile loading may also be experienced. The center mandrel typically has tensile loading applied thereto when setting the packer and when the packer is in its operating position.

One new method of the invention is a well bore process comprising the steps of positioning a downhole tool into engagement with the well bore; prior to the step of positioning, constructing the tool such that a component thereof is made of a non-metallic material; and then drilling the tool out of the well bore. The tool may be selected from the group consisting packers and bridge plugs, but is not limited to these devices.

The component made of non-metallic material, may be one of several such components. The components may be substantially subject to compressive loading. Such components in the tool may include lock ring housings, slips, slip wedges and slip supports. Some components, such as center mandrels of such tools may be substantially subjected to tensile loading.

In another embodiment, the step of drilling is carried out using a polycrystalline diamond compact bit. Regardless of the type of drill bit used, the process may further comprise the step of drilling using a drill bit without substantially varying the weight applied to the drill bit.

In another method of the invention, a well bore process comprises the steps of positioning and setting a packing device in the well bore, a portion of the device being made of engineering grade plastic; contacting the device with well fluids; and drilling out the device using a drill bit having no moving parts such as a polycrystalline diamond compact bit. This or a similar drill bit might have been previously used in drilling the well bore itself, so the process may be said to further comprise the step of, prior to the step of positioning and setting the packer, drilling at least a portion of the well bore using a drill bit such as a polycrystalline diamond compact bit.

In one preferred embodiment, the step of contacting the packer is at a pressure of less than about 5,000 psi and a temperature of less than about 250° F, although higher pressures and temperatures may also be encountered.

It is an important object of the invention to provide a downhole tool apparatus utilizing components made of nonmetallic materials and methods of drilling thereof.

It is another object of the invention to provide a well bore packing apparatus using components made of engineering grade plastic.

An additional object of the invention is to provide a packing apparatus having a valve housing disposed substantially below a lower end of a center mandrel and having a valve in the valve housing below the lower end of the center mandrel.

It is a further object of the invention to provide a packing apparatus which may be drilled by alternate methods to those using standard rotary drill bits.

Additional objects and advantages of the invention will become apparent as the following detailed description of the preferred embodiments is read in conjunction with the drawings which illustrate such preferred embodiments.

BRIEF DESCRIPTION OF THE DRAWINGS

FIG. 1 generally illustrates the downhole tool of the present invention positioned in a well bore with a drill bit disposed thereabove.

FIG. 2 illustrates a cross section of one embodiment of a drillable packer made in accordance with the invention.

FIGS. 3A and 3B show a cross section of a second embodiment of a drillable packer.

FIGS. 4A and 4B show a third drillable packer embodiment.

FIGS. 5A and 5B illustrate a fourth embodiment of a drillable packer.

FIGS. 6A and 6B show a fifth drillable packer embodiment with a poppet valve therein.

FIG. 7 shows a cross section of one embodiment of a drillable bridge plug made in accordance with the present invention.

FIG. 8 illustrates a second embodiment of a drillable bridge plug.

DESCRIPTION OF THE PREFERRED EMBODIMENT

Referring now to the drawings, and more particularly to FIG. 1, the downhole tool apparatus of the present invention is shown and generally designated by the numeral 10. Apparatus 10, which may include, but is not limited to, packers, bridge plugs, or similar devices, is shown in an operating position in a well bore 12. Apparatus 10 can be set in this position by any manner known in the art such as setting on a tubing string or wire line. A drill bit 14 connected to the end of a tool or tubing string 16 is shown above apparatus 10 in a position to commence the drilling out of apparatus 10 from well bore 12. Methods of drilling will be further discussed herein.

First Packer Embodiment

Referring now to FIG. 2, the details of a first squeeze packer embodiment 20 of apparatus 10 will be described. The size and configuration of packer 20 is substantially the same as the previously mentioned prior art EZ Drill SV® squeeze packer. Packer 20 defines a generally central opening 21 therein.

Packer 20 comprises a center mandrel 22 on which most of the other components are mounted. A lock ring housing 24 is disposed around an upper end of mandrel 22 and generally encloses a lock ring 26.

Disposed below lock ring housing 24 and pivotally connected thereto are a plurality of upper slips 28 initially held in place by a retaining band 30. A generally conical upper slip wedge is disposed around mandrel 22 adjacent to upper slips 30. Upper slip wedge 32 is held in place on mandrel 22 by a wedge retaining ring 34 and a plurality of screws 36.

Adjacent to the lower end of upper slip wedge 32 is an upper back-up ring 37 and an upper packer shoe 38 connected to the upper slip wedge by a pin 39. Below upper packer shoe 38 are a pair of end packer elements 40 separated by center packer element 42. A lower packer shoe 44 and lower back-up ring 45 are disposed adjacent to the lowermost end packer element 40.

A generally conical lower slip wedge 46 is positioned around mandrel 22 adjacent to lower packer shoe 44, and a pin 48 connects the lower packer shoe to the lower slip wedge.

Lower slip wedge 46 is initially attached to mandrel 22 by a plurality of screws 50 and a wedge retaining ring 52 in a manner similar to that for upper slip wedge 32. A plurality of lower slips 54 are disposed adjacent to lower slip wedge 46 and are initially held in place by a retaining band 56. Lower slips 54 are pivotally connected to the upper end of a lower slip support 58. Mandrel 22 is attached to lower slip support 58 at threaded connection 60.

Disposed in mandrel 22 at the upper end thereof is a tension sleeve 62 below which is an internal seal 64. Tension sleeve 62 is adapted for connection with a setting tool (not shown) of a kind known in the art.

A collet-latch sliding valve 66 is slidably disposed in central opening 21 at the lower end of mandrel 22 adjacent to fluid ports 68 in the mandrel. Fluid ports 68 in mandrel 22 are in communication with fluid ports 70 in lower slip housing 58. The lower end of lower slip support 58 is closed below ports 70.

Sliding valve 66 defines a plurality of valve ports 72 which can be aligned with fluid ports 68 in mandrel 22 when sliding valve 66 is in an open position. Thus, fluid can flow through central opening 21.

On the upper end of sliding valve 66 are a plurality of collet fingers 67 which are adapted for latching and unlatching with a valve actuation tool (not shown) of a kind known in the art. This actuation tool is used to open and close sliding valve 66 as further discussed herein. As illustrated in FIG. 2, sliding valve 66 is in a closed position wherein fluid ports 68 are sealed by upper and lower valve seals 74 and 76.

In prior art drillable packers and bridge plugs of this type, mandrel 22 is made of a medium hardness cast iron, and lock ring housing 24, upper slip wedge 32, lower slip wedge 46 and lower slip support 58 are made of soft cast iron for drillability. Most of the other components are made of aluminum, brass or rubber which, of course, are relatively easy to drill. Prior art upper and lower slips 28 and 54 are made of hard cast iron, but are grooved so that they will easily be broken up in small pieces when contacted by the drill bit during a drilling operation.

As previously described, the soft cast iron construction of prior art lock ring housings, upper and lower slip wedges, and lower slip supports are adapted for relatively high pressure and temperature conditions, while a majority of well applications do not require a design for such conditions. Thus, the apparatus of the present invention, which is generally designed for pressures lower than 10,000 psi and temperatures lower than 425° F., utilizes engineering grade plastics for at least some of the components. For example, the apparatus may be designed for pressures up to about 5,000 psi and temperatures up to about 250° F., although the invention is not intended to be limited to these particular conditions.

In first packer embodiment 20, at least some of the previously soft cast iron components of the slip means, such as lock ring housing 24, upper and lower slip wedges 32 and 46 and lower slip support 58 are made of engineering grade plastics. In particular, upper and lower slip wedges 32 and 46 are subjected to substantially compressive loading. Since engineering grade plastics exhibit good strength in compression, they make excellent choices for use in components subjected to compressive loading. Lower slip support 58 is also subjected to substantially compressive loading and can be made of engineering grade plastic when packer 20 is subjected to relative low pressures and temperatures.

Lock ring housing 24 is mostly in compression, but does exhibit some tensile loading. However, in most situations, this tensile loading is minimal, and lock ring housing 24 may also be made of an engineering grade plastic of substantially the same type as upper and lower slip wedges 32 and 46 and also lower slip housing 58.

Upper and lower slips 28 and 54 may also be of plastic in some applications. Hardened inserts for gripping well bore 12 when packer 20 is set may be required as part of the plastic slips. Such construction is discussed in more detail herein for other embodiments of the invention.

Lock ring housing 24, upper slip wedge 32, lower slip wedge 46, and lower slip housing 58 comprise approximately 75% of the cast iron of the prior art squeeze packers. Thus, replacing these components with similar components made of engineering grade plastics will enhance the drillability of packer 20 and reduce the time and cost required therefor.

Mandrel 22 is subjected to tensile loading during setting and operation, and many plastics will not be acceptable materials therefor. However, some engineer-

. . . . . . good tensile loading characteristics, so that construction of mandrel 22 from such plastics is possible. Reinforcements may be provided in the plastic resin as necessary.

EXAMPLE

A first embodiment packer 20 was constructed in which upper slip wedge 32 and lower slip wedge 46 were constructed by molding the parts to size from a phenolic resin plastic with glass reinforcement. The specific material used was Fiberite 4056J manufactured by Fiberite Corporation of Winona, Minn. This material is classified by the manufacturer as a two stage phenolic with glass reinforcement. It has a tensile strength of 18,000 psi and a compressive strength of 40,000 psi.

The test packer 20 held to 8,500 psi without failure to wedges 32 and 46, more than sufficient for most well bore conditions.

Second Packer Embodiment

Referring now to FIGS. 3A and 3B, the details of a second squeeze packer embodiment 100 of packing apparatus 10 are shown. While first embodiment 20 incorporates the same configuration and general components as prior art packers made of metal, second packer embodiment 100 and the other embodiments described herein comprise specific design features to accommodate the benefits and problems of using nonmetallic components, such as plastic.

Packer 100 comprises a center mandrel 102 on which most of the other components are mounted. Mandrel 102 may be described as a thick cross-sectional mandrel having a relatively thicker wall thickness than typical packer mandrels, including center mandrel 22 of first embodiment 20. A thick cross-sectional mandrel may be generally defined as one in which the central opening therethrough has a diameter less than about half of the outside diameter of the mandrel. That is, mandrel central opening 104 in central mandrel 102 has a diameter less than about half the outside of center mandrel 102. It is contemplated that a thick cross-sectional mandrel will be required if it is constructed from a material having relatively low physical properties. In particular, such materials may include phenolics and similar plastic materials.

An upper support 106 is attached to the upper end of center mandrel 102 at threaded connection 108. In an alternate embodiment, center mandrel 102 and upper support 106 are integrally formed and there is no threaded connection 108. A spacer ring or upper slip support 110 is disposed on the outside of mandrel 102 just below upper support 106. Spacer ring 110 is initially attached to center mandrel 102 by at least one shear pin 112. A downwardly and inwardly tapered shoulder 114 is defined on the lower side of spacer ring 110.

Disposed below spacer ring 110 are a plurality of upper slips 116. A downwardly and inwardly sloping shoulder 118 forms the upper end of each slip 116. The taper of each shoulder 118 conforms to the taper of shoulder 114 on spacer ring 110, and slips 116 are adapted for sliding engagement with shoulder 114, as will be further described herein.

An upwardly and inwardly facing taper 120 is defined in the lower end of each slip 116. Each taper 120 generally faces the outside of center mandrel 102.

A plurality of hardened inserts or teeth 122 preferably are molded into upper slips 116. In the embodiment shown in FIG. 3A, inserts 122 have a generally square

cross section and are positioned at an angle so that a radially outer edge 124 protrudes from the corresponding upper slip 116. Outer edge 124 is adapted for grippingly engaging well bore 112 when packer 100 is set. It is not intended that inserts 122 be of square cross section and have a distinct outer edge 124. Different shapes of inserts may also be used. Inserts 122 can be made of any suitable hardened material.

An upper slip wedge 126 is disposed adjacent to upper slips 116 and engages taper 120 therein. Upper slip wedge 126 is initially attached to center mandrel 102 by one or more shear pins 128.

Below upper slip wedge 126 are upper back-up ring 37, upper packer shoe 38, end packer elements 40 separated by center packer element 42, lower packer shoe 44 and lower back-up ring 45 which are substantially the same as the corresponding components in first embodiment packer 20. Accordingly, the same reference numerals are used.

Below lower back-up ring 45 is a lower slip wedge 130 which is initially attached to center mandrel 102 by a shear pin 132. Preferably, lower slip wedge 130 is identical to upper slip wedge 126 except that it is positioned in the opposite direction.

Lower slip wedge 130 is in engagement with an inner taper 134 in a plurality of lower slips 136. Lower slips 136 have inserts or teeth 138 molded therein, and preferably, lower slips 136 are substantially indentical to upper slips 116.

Each lower slip 136 has a downwardly facing shoulder 140 which tapers upwardly and inwardly. Shoulders 140 are adapted for engagement with a corresponding shoulder 142 defining the upper end of a valve housing 144. Shoulder 142 also tapers upwardly and inwardly. Thus, valve housing 144 may also be considered a lower slip support 144.

Referring now also to FIG. 3B, valve housing 146 is attached to the lower end of center mandrel 102 at threaded connection 146. A sealing means, such as O-ring 148, provides sealing engagement between valve housing 144 and center mandrel 102.

Below the lower end of center mandrel 102, valve housing 104 defines a longitudinal opening 150 therein having a longitudinal rib 152 in the lower end thereof. At the upper end of opening 150 is an annular recess 154.

Below opening 150, valve housing 144 defines a housing central opening including a bore 156 therein having a closed lower end 158. A plurality of transverse ports 160 are defined through valve housing 144 and intersect bore 156. The wall thickness of valve housing 144 is thick enough to accommodate a pair of annular seal grooves 162 defined in bore 156 on opposite sides of ports 160.

Slidably disposed in valve housing 144 below center mandrel 102 is a sliding valve 164. Sliding valve 164 is the same as, or substantially similar to, sliding valve 66 in first embodiment packer 20. At the upper end of sliding valve 164 are a plurality of upwardly extending collet fingers 166 which initially engage recess 154 in valve housing 144. Sliding valve 164 is shown in an uppermost, closed position in FIG. 3B. It will be seen that the lower end of center mandrel 102 prevents further upward movement of sliding valve 164.

Sliding valve 164 defines a valve central opening 168 therethrough which is in communication with central opening 104 in center mandrel 102. A chamfered shoul-

der 170 is located at the upper end of valve central opening 168.

Sliding valve 164 defines a plurality of substantially transverse ports 172 therethrough which intersect valve central opening 168. As will be further discussed herein, ports 172 are adapted for alignment with ports 160 in valve housing 144 when sliding valve 164 is in a downward, open position thereof. Rib 152 fits between a pair of collet fingers 166 so that sliding valve 164 cannot rotate within valve housing 144, thus insuring proper alignment of ports 172 and 160. Rib 152 thus provides an alignment means.

A sealing means, such as O-ring 174, is disposed in each seal groove 162 and provides sealing engagement between sliding valve 164 and valve housing 144. It will thus be seen that when sliding valve 164 is moved downwardly to its open position, O-rings 174 seal on opposite sides of ports 172 in the sliding valve.

Referring again to FIG. 3A, a tension sleeve 174 is disposed in center mandrel 102 and attached thereto to threaded connection 176 Tension sleeve 174 has a threaded portion 178 which extends from center mandrel 102 and is adapted for connection to a standard setting tool (not shown) of a kind known in the art.

Below tension sleeve 174 is an internal seal 180 similar to internal seal 64 in first embodiment 20.

Third Packer Embodiment

Referring now to FIGS. 4A and 4B, a third squeeze packer embodiment of the present invention is shown and generally designated by the numeral 200. It will be clear to those skilled in the art that third embodiment 200 is similar to second packer embodiment 100 but has a couple of significant differences.

Packer 200 comprises a center mandrel 202. Unlike center mandrel 102 in second embodiment 100, center mandrel 202 is a thin cross-sectional mandrel. That is, it may be said that center mandrel 102 has a mandrel central opening 204 with a diameter greater than about half of the outside diameter of center mandrel 202. It is contemplated that thin cross-sectional mandrels, such as center mandrel 202, may be made of materials having relatively higher physical properties, such as epoxy resins.

The external components of third packer embodiment 200 which fit on the outside of center mandrel 202 are substantially identical to the outer components on second embodiment 100, and therefore the same reference numerals are shown in FIG. 4A. In a manner similar to second embodiment packer 100, center mandrel 202 and upper support 106 may be integrally formed so that there is no threaded connection 108.

The lower end of center mandrel 202 is attached to a valve housing 206 at threaded connection 208. On the upper end of valve housing 206 is an upwardly and inwardly tapered shoulder 210 against which shoulder 104 on lower slips 136 are slidably disposed. Thus, valve housing 206 may also be referred to as a lower slip support 206.

Referring now also to FIG. 4B, a sealing means, such as O-ring 212, provides sealing engagement between center mandrel 202 and valve housing 206.

Valve housing 206 defines a housing central opening including a bore 214 therein with a closed lower end 216. At the upper end of bore 214 is an annular recess 218. Valve housing 204 defines a plurality of substantially transverse ports 220 therethrough which intersect bore 214.

Slidably disposed in bore 214 in valve housing 206 is a sliding valve 222. At the upper end of sliding valve 222 are a plurality of collet fingers 224 which initially engage recess 218.

Sliding valve 222 defines a plurality of substantially transverse ports 226 therein which intersect a valve central opening 228 in the sliding valve. Valve central opening 228 is in communication with mandrel central opening 204 in center mandrel 202. At the upper end of central opening 228 is a chamfered shoulder 230.

As shown in FIG. 4B, sliding valve 222 is in an uppermost closed position. It will be seen that the lower end of center mandrel 202 prevents further upward movement of sliding valve 222. When sliding valve 222 is moved downwardly to an open position, ports 226 are substantially aligned with ports 220 in valve housing 206. An alignment means, such as an alignment bolt 232, extends from valve housing 206 inwardly between a pair of adjacent collet fingers 224. A sealing means, such as O-ring 234, provides sealing engagement between alignment bolt 232 and valve housing 206. Alignment bolt 234 prevents rotation of sliding valve 222 within valve housing 204 and insures proper alignment of ports 226 and 220 when sliding valve 222 is in its downwardmost, open position.

The wall thickness of sliding valve 222 is sufficient to accommodate a pair of spaced seal grooves 234 are defined in the outer surface of sliding valve 222, and as seen in FIG. 4B, seal grooves 234 are disposed on opposite sides of ports 220 when sliding valve 222 is in the open position shown. A sealing means, such as seal 236, is disposed in each groove 234 to provide sealing engagement between sliding valve 222 and bore 214 in valve housing 206.

Referring again to FIG. 4A, a tension sleeve 238 is attached to the upper end of center mandrel 202 at threaded connection 240. A threaded portion 242 of tension sleeve 238 extends upwardly from center mandrel 202 and is adapted for engagement with a setting apparatus (not shown) of a kind known in the art.

An internal seal 244 is disposed in the upper end of center mandrel 202 below tension sleeve 238.

Fourth Packer Embodiment

Referring now to FIGS. 5A and 5B, a fourth squeeze packer embodiment is shown and generally designated by the numeral 300. As illustrated, fourth embodiment 300 has the same center mandrel 202, and all of the components positioned on the outside of center mandrel 202 are identical to those in the second and third packer embodiments. Therefore, the same reference numerals are used for these components. Tension sleeve 238 and internal seal 244 positioned on the inside of the upper end of center mandrel 202 are also substantially identical to the corresponding components in third embodiment packer 200 and therefore shown with the same reference numerals.

The difference between fourth packer embodiment 300 and third packer embodiment 200 is that in the fourth embodiment shown in FIGS. 5A and 5B, the lower end of center mandrel 202 is attached to a different valve housing 302 at threaded connection 304. Shoulder 140 on each lower slip 136 slidingly engages an upwardly and inwardly tapered shoulder 306 on the top of valve housing 302. Thus, valve housing 302 may also be referred to as lower slip support 302.

Referring now to FIG. 5B, a sealing means, such as O-ring 308, provides sealing engagement between the lower end of center mandrel 202 and valve housing 302.

Valve housing 302 defines a housing central opening including a bore 310 therein with a closed lower end 312. A bumper seal 314 is disposed adjacent to end 312.

Valve housing 302 defines a plurality of substantially transverse ports 316 therethrough which intersect bore 310. A sliding valve 318 is disposed in bore 310, and is shown in an uppermost, closed position in FIG. 5B. It will be seen that the lower end of center mandrel 202 prevents upward movement of sliding valve 318. Sliding valve 318 defines a valve central opening 320 therethrough which is in communication with mandrel central opening 204 in center mandrel 202. At the upper end of valve central opening 320 in sliding valve 318 is an upwardly facing chamfered shoulder 322.

On the outer surface of sliding valve 318, a pair of spaced seal grooves 324 are defined. In the closed position shown in FIG. 5B, seal grooves 324 are on opposite sides of ports 316 in valve housing 302. A sealing means, such as seal 326, is disposed in each seal groove 324 and provides sealing engagement between sliding valve 318 and bore 310 in valve housing 302.

When sliding valve 318 is opened, as will be further described herein, the sliding valve 318 is moved downwardly such that upper end 328 thereof is below ports 316 in valve housing 302. Downward movement of sliding valve 318 is checked when lower end 330 thereof contacts bumper seal 314. Bumper seal 314 is made of a resilient material which cushions the impact of sliding valve 318 thereon.

Fifth Packer Embodiment

Referring now to FIGS. 6A and 6B, a fifth squeeze packer embodiment is shown and generally designated by the numeral 400. As illustrated, fifth packer embodiment 400 incorporates the same thick cross-sectional center mandrel 102 as does second packer embodiment 100 shown in FIGS. 3A and 3B. Also, the external components positioned on center mandrel 102 are the same as in the second, third and fourth packer embodiments, so the same reference numerals will be used. Further, tension sleeve 174 and internal seal 180 in second embodiment 100 are also incorporated in fifth embodiment 400, and therefore these same reference numerals have also been used.

The difference between fifth packer embodiment 400 and second embodiment 100 is that the lower end of center mandrel 102 is attached to a lower slip support 402 at threaded connection 404. Shoulders 140 on lower slips 136 slidingly engage an upwardly and inwardly tapered shoulder 406 at the upper end of lower slip support 402.

Referring now to FIG. 6B, a sealing means, such as O-ring 408, provides sealing engagement between the lower end of center mandrel 102 and lower slip support 402.

Lower slip support 402 defines a first bore 410 therein and a larger second bore 412 spaced downwardly from the first bore. A tapered seat surface 414 extends between first bore 410 and second bore 412.

The lower end of lower support 402 is attached to a valve housing 416 at threaded connection 418. Valve housing 416 defines a first bore 420 and a smaller second bore 422 therein. An upwardly facing annular shoulder 424 extends between first bore 420 and second bore 422. Below second bore 422, valve housing 416 defines a third bore 426 therein with an internally threaded surface 428 forming a port at the lower end of the valve housing.

Disposed in first bore 420 in valve housing 416 is a valve body 430 with an upwardly facing annular shoulder 432 thereon. An elastomeric valve seal 434 and a valve spacer 436, which provides support for the valve seal, are positioned adjacent to shoulder 432 on valve body 430. A conical valve head 438 is positioned above valve seal 434 and is attached to valve body 430 at threaded connection 440. It will be seen by those skilled in the art that valve seal 434 is adapted for sealing engagement with seat surface 414 in lower slip support 402 when valve body 430 is moved upwardly.

The lower end of valve body 430 is connected to a valve holder 442 by one or more pins 444. Valve holder 442 is disposed in second bore 422 of valve housing 416. A sealing means, such as O-ring 446 provides sealing engagement between valve holder 442 and valve housing 416.

Above shoulder 424 in valve housing 416, valve body 430 has a radially outwardly extending flange 448 thereon. A biasing means, such as spring 450, is disposed between flange 448 and shoulder 424 for biasing valve body 430 upwardly with respect to valve housing 416.

Valve holder 442 defines a first bore 452 and a smaller second bore 454 therein with an upwardly facing chamfered shoulder 456 extending therebetween. A ball 458 is disposed in valve holder 442 and is adapted for engagement with shoulder 456.

First Bridge Plug Embodiment

Referring now to FIG. 7, a first bridge plug embodiment of the present invention is shown and generally designated by the numeral 500. First bridge plug embodiment 500 comprises the same center mandrel 102 and the external components positioned thereon as does the second packer embodiment 100. Therefore, the reference numerals for these components shown in FIG. 7 are the same as in FIG. 3A.

The lower end of center mandrel 102 in first bridge plug embodiment 500 is connected to a lower slip support 502 at threaded connection 504. An upwardly and inwardly tapered shoulder 506 on lower slip support 502 engages shoulders 140 on lower slips 136. As with the other embodiments, slips 136 are adapted for sliding along shoulder 506.

Lower slip support 502 defines a bore 508 therein which is in communication with mandrel central opening 104 in center mandrel 102.

A bridging plug 510 is disposed in the upper portion of mandrel central opening 104 in center mandrel 102 and is sealingly engaged with internal seal 180. A radially outwardly extending flange 512 prevents bridging plug 510 from moving downwardly through center mandrel 102.

Above bridging plug 510 is tension sleeve 174, previously described for second packer embodiment 100.

Second Bridge Plug Embodiment

Referring now to FIG. 8, a second bridge plug embodiment of the present invention is shown and generally designated by the numeral 600. Second bridge plug embodiment 600 uses the same thin cross-sectional mandrel 202 as does third packer embodiment 200 shown in FIG. 4A. Also, the external components positioned on center mandrel 202 are the same as previously de-

scribed, so the same reference numerals are used in FIG. 8.

In second bridge plug embodiment 600, the lower end of center mandrel 202 is attached to the same lower slip support 502 as first bridge plug embodiment 500 at threaded connection 602. It will be seen that bore 508 in lower slip support 502 is in communication with mandrel central opening 204 in center mandrel 202.

A bridging plug 604 is positioned in the upper end of mandrel central opening 204 in center mandrel 202. A shoulder 608 in central opening 204 prevents downward movement of bridging plug 604. A sealing means, such as a plurality of O-rings 606, provide sealing engagement between bridging plug 604 and center mandrel 202.

Tension sleeve 238, previously described, is positioned above bridging plug 604.

Setting And Operation Of The Apparatus

Downhole tool apparatus 10 is positioned in well bore 12 and set into engagement therewith in a manner similar to prior art devices made with metallic components. For example, a prior art apparatus and setting thereof is disclosed in the above-referenced U.S. Pat. No. 4,151,875 to Sullaway. This patent is incorporated herein by reference.

For first packer embodiment 20, the setting tool pulls upwardly on tension sleeve 62, and thereby on mandrel 22, while holding lock ring housing 24. The lock ring housing is thus moved relatively downwardly along mandrel 22 which forces upper slips 28 outwardly and shears screws 36, pushing upper slip wedge 32 downwardly against packer elements 40 and 42. Screws 50 are also sheared and lower slip wedge 46 is pushed downwardly toward lower slip support 58 to force lower slips 54 outwardly. Eventually, upper slips 28 and lower slips 54 are placed in gripping engagement with well bore 12 and packer elements 40 and 42 are in sealing engagement with the well bore. The action of upper slips 28 and 54 prevent packer 20 from being unset. As will be seen by those skilled in the art, pressure below packer 20 cannot force the packer out of well bore 12, but instead, causes it to be even more tightly engaged.

Eventually, in the setting operation, tension sleeve 62 is sheared, so the setting tool may be removed from the well bore.

The setting of second packer embodiment 100, third packer embodiment 200, fourth packer embodiment 300, fifth packer embodiment 400, first bridge plug embodiment 500 and second bridge plug embodiment 600 is similar to that for first packer embodiment 20. The setting tool is attached to either tension sleeve 174 or 238. During setting, the setting tool pushes downwardly on upper slip support 110, thereby shearing shear pin 112. Upper slips 116 are moved downwardly with respect to upper slip wedge 126. Tapers 120 and upper slips 116 slide along upper slip wedge 126, and shoulders 118 on upper slips 116 slide along shoulder 114 on upper slip support 110. Thus, upper slips 116 are moved radially outwardly with respect to center mandrel 102 or 202 such that edges 124 of inserts 122 grippingly well bore 12.

Also during the setting operation, upper slip wedge 126 is forced downwardly, shearing shear pin 128. This in turn causes packer elements 40 and 42 to be squeezed outwardly into sealing engagement with the well bore.

The lifting on center mandrel 102 or 202 causes the lower slip support (valve housing 144 in first packer embodiment 100, valve housing 206 in second packer embodiment 200, valve housing 302 in fourth packer embodiment 300, lower slip support 402 in fifth packer embodiment 400, and lower slip support 502 in first bridge plug embodiment 500 and second bridge plug embodiment 600) to be moved up and lower slips 136 to be moved upwardly with respect to lower slip wedge 130. Tapers 134 in lower slips 136 slide along lower slip wedge 130, and shoulders 140 on lower slips 136 slide along the corresponding shoulder 142, 210, 306, 406, or 506. Thus, lower slips 136 are moved radially outwardly with respect to center mandrel 102 or 202 so that inserts 138 grippingly engage well bore 12.

Also during the setting operation, lower slip wedge 130 is forced upwardly, shearing shear pin 132, to provide additional squeezing force on packer elements 40 and 42.

The engagement of inserts 122 in upper slips 116 and inserts 138 in lower slips 136 with well bore 12 prevent packers 100, 200, 300, 400 and bridge plugs 500, 600 from coming unset.

Once any of packers 20, 100, 200, 300, 400 are set, the valves therein may be actuated in a manner known in the art. Sliding valve 164 in second packer embodiment 126, and sliding valve 22 in third packer embodiment 200 are set in a similar, if not identical manner. Sliding valve 318 in fourth packer embodiment 300 is also set in a similar manner, but does not utilize collets, nor is alignment of sliding valve 318 with respect to ports 316 in valve housing 302 important. Sliding valve 318 is simply moved below ports 316 to open the valve. Bumper seal 314 cushions the downward movement of sliding valve 318, thereby minimizing the possibility of damage to sliding valve 318 or valve housing 302 during an opening operation.

In fifth packer embodiment 400, the valve assembly comprising valve body 432, valve seal 434, valve spacer 436, valve head 438 and valve holder 442 is operated in a manner substantially identical to that of the Halliburton EZ Drill® squeeze packer of the prior art.

Drilling Out The Packer Apparatus

Drilling out any embodiment of downhole tool 10 may be carried out by using a standard drill bit at the end of tubing string 16. Cable tool drilling may also be used. With a standard "tri-cone" drill bit, the drilling operation is similar to that of the prior art except that variations in rotary speed and bit weight are not critical because the nonmetallic materials are considerably softer than prior art cast iron, thus making tool 10 much easier to drill out. This greatly simplifies the drilling operation and reduces the cost and time thereof.

In addition to standard tri-cone drill bits, and particularly if tool 10 is constructed utilizing engineering grade plastics for the mandrel as well as for slip wedges, slips, slip supports and housings, alternate types of drill bits may be used which would be impossible for tools constructed substantially of cast iron. For example, polycrystalline diamond compact (PDC) bits may be used. Drill bit 14 in FIG. 1 is illustrated as a PDC bit. Such drill bits have the advantage of having no moving parts which can jam up. Also, if the well bore itself was drilled with a PDC bit, it is not necessary to replace it with another or different type bit in order to drill out tool 10.

While specific squeeze packer and bridge plug configurations of packing apparatus 10 has been described herein, it will be understood by those skilled in the art

ponents selected of non-metallic materials, such as engineering grade plastics.

Additionally, components of the various packer embodiments may be interchanged. For example, thick cross-sectional center mandrel 102 may be used with valve housing 206 in second packer embodiment 200 or valve housing 302 in fourth packer embodiment 300. Similarly, thin cross-sectional center mandrel 202 could be used with valve body 144 in second packer embodiment 100 or lower slip support 402 and valve housing 416 in fifth packer embodiment 400. The intent of the invention is to provide devices of flexible design in which a variety of configurations may be used.

It will be seen, therefore, that the downhole tool packer apparatus and methods of drilling thereof of the present invention are well adapted to carry out the ends and advantages mentioned as well as those inherent therein. While presently preferred embodiments of the apparatus and various drilling methods have been discussed for the purposes of this disclosure, numerous changes in the arrangement and construction of parts and the steps of the methods may be made by those skilled in the art. In particular, the invention is not intended to be limited to squeeze packers or bridge plugs. All such changes are encompassed within the scope and spirit of the appended claims.

What is claimed is:

1. A well bore process comprising the steps of:

constructing a downhole tool such that a component thereof is made of a non-metallic material, said tool comprising:

a center mandrel; and

a plurality of slips disposed around said mandrel for grippingly engaging a well bore when in a set position;

wherein, at least one of said mandrel and said plurality of slips is said component;

positioning said downhole tool into locking, sealing engagement with said well bore; and

drilling said tool out of said well bore.

2. The process of claim 1 wherein said tool is selected from the group consisting of packers and bridge plugs.

3. The process of claim 1 wherein said component is subject to compressive loading.

4. The process of claim 1 wherein said component is subject to tensile loading.

5. The process of claim 1 wherein said center mandrel defines a central opening therein having a diameter less than about half an outside diameter of said center mandrel.

6. The process of claim 1 wherein said center mandrel defines a central opening therein having a diameter greater than about half the outside diameter of said center mandrel.

7. The process of claim 1 wherein said non-metallic material is plastic.

8. The process of claim 7 wherein said component is molded.

9. The process of claim 7 wherein said plastic is selected from the group consisting of nylon, phenolic material or epoxy resin.

10. The process of claim 9 wherein said plastic is a phenolic material and is selected from the group consisting of Fiberite FM4056J, Fiberite FM4005 or Resinoid 1360.

11. The process of claim 1 wherein said step of drilling is carried out with a polycrystalline diamond compact bit.

12. The process of claim 1 wherein said step of drilling is carried out using a drill bit without substantially varying weight applied to said drill bit.

13. A well bore process comprising the steps of:

positioning and setting a packing device into locked, sealing engagement with a well bore, a portion of said device being made of engineering grade plastic;

contacting said device with well fluids; and

drilling out said device using a polycrystalline diamond compact bit.

14. The process of claim 13 wherein said step of contacting is at a temperature of less than about 250° F.

15. The process of claim 13 wherein said step of contacting is at a pressure of less than about 5,000 psi.

16. The process of claim 13 wherein said portion of said device is at least one of a housing, slip, slip wedge, slip support, and mandrel thereof.

17. The process of claim 13 further comprising the step of, prior to said step of positioning and setting said device, drilling at least a portion of said well bore using a polycrystalline diamond compact bit.

18. The process of claim 13 wherein said step of drilling is carried out without substantially varying weight applied to said bit.

19. A downhole apparatus for use in a well bore, said apparatus comprising:

a center mandrel; and

slip means disposed on said mandrel for grippingly engaging said well bore when in a set position, said slip means comprising:

a slip wedge made of a non-metallic material; and

slips made of non-metallic material.

20. The apparatus of claim 19 characterized as a packing apparatus and further comprising packing means disposed on said mandrel for sealingly engaging said well bore when in a set position.

21. The apparatus of claim 20 wherein said slip means is an upper slip means disposed above said packing means and further comprising a lower slip means disposed below said packing means, said lower slip means comprising another slip wedge made of a non-metallic material.

22. The apparatus of claim 19 wherein said slip means comprises a slip support made of a non-metallic material.

23. The apparatus of claim 19 further comprising a plurality of hardened inserts molded into said material of said slips.

24. The apparatus of claim 19 wherein said non-metallic material is an engineering grade plastic.

25. The apparatus of claim 24 wherein said plastic is nylon.

26. The apparatus of claim 24 wherein said plastic is a phenolic material.

27. The apparatus of claim 26 wherein said phenolic material is one of Fiberite FM4056J, Fiberite FM4005 and Resinoid 1360.

28. The apparatus of claim 24 wherein said plastic is an epoxy resin.

29. The apparatus of claim 24, wherein said wedge is molded to size.

30. A downhole apparatus for use in a well bore, said apparatus comprising:

a center mandrel made of a non-metallic material; and

slip means disposed on said mandrel for grippingly engaging said well bore when in a set position.

31. The apparatus of claim 30 characterized as a packing apparatus and further comprising packing means disposed on said mandrel for sealingly engaging said well bore when in a set position.

32. The apparatus of claim 30 wherein said slip means comprises a wedge made of a non-metallic material.

33. The apparatus of claim 30 wherein said slip means comprises slips made of a non-metallic material.

34. The apparatus of claim 30 wherein said non-metallic material is an engineering grade plastic.

35. The apparatus of claim 34 wherein said plastic is nylon.

36. The apparatus of claim 34 wherein said plastic is a phenolic material.

37. The apparatus of claim 36 wherein said phenolic material is Fiberite FM4056J.

38. The apparatus of claim 34 wherein said mandrel is molded to size.

39. The apparatus of claim 34 wherein said mandrel has a central opening defined therethrough having a diameter less than about half an outside diameter of said mandrel.

40. The apparatus of claim 34 wherein said mandrel has a central opening defined therethrough having a diameter greater than about half an outside diameter of said mandrel.

41. The apparatus of claim 34 wherein said plastic is an epoxy resin.

42. A downhole apparatus for use in a well bore, said apparatus comprising:

a center mandrel; and

a plurality of slips disposed around said mandrel for grippingly engaging said well bore when in a set position, said slips being made of a non-metallic material.

43. The apparatus of claim 42 characterized as a packing apparatus and further comprising packing means disposed on said mandrel for sealingly engaging said well bore when in a set position; and

wherein some of said slips are disposed above said packing means and some of said slips are disposed below said packing means.

44. The apparatus of claim 42 further comprising a wedge disposed adjacent to said slips, said wedge being made of a non-metallic material.

45. The apparatus of claim 42 wherein said mandrel is made of a non-metallic material.

46. The apparatus of claim 42 wherein said non-metallic material is an engineering grade plastic.

47. The apparatus of claim 46 wherein said plastic material is nylon.

48. The apparatus of claim 46 wherein said plastic is a phenolic material.

49. The apparatus of claim 48 wherein said phenolic material is Fiberite FM4056J.

50. The apparatus of claim 46 wherein said plastic is an epoxy resin.

51. The apparatus of claim 46 wherein said slips are molded of said plastic material.

52. The apparatus of claim 51 further comprising a plurality of hardened inserts molded into said plastic.

53. The apparatus of claim 52 wherein each of said inserts has an edge adapted for grippingly engaging said well bore.

54. A packing apparatus for use in a well bore, said apparatus comprising:

a mandrel made of a non-metallic material;

an upper slip support disposed on said mandrel and made of a non-metallic material;

a plurality of upper slips disposed around said mandrel and substantially made of a non-metallic material;

packing means disposed on said mandrel below said upper slips for sealingly engaging said well bore when in a set position;

a plurality of lower slips disposed around said mandrel below said packing means and substantially made of a non-metallic material; and

a lower slip support attached to said mandrel and made of a non-metallic material.

55. The apparatus of claim 54 wherein said non-metallic material of any of said mandrel, upper slip support, upper slips, lower slips and lower slip support is an engineering grade plastic.

56. The apparatus of claim 55 wherein said plastic is nylon.

57. The apparatus of claim 56 wherein said phenolic material is one of Fiberite FM4056J, Fiberite FM4005 and Resinoid 1360.

58. The apparatus of claim 55 wherein said plastic is a phenolic material.

59. The apparatus of claim 55 wherein said plastic is an epoxy resin.

60. The apparatus of claim 55 wherein any of said mandrel, upper slip support upper slips, lower slips and lower slip support may be molded to size.

61. The apparatus of claim 59 wherein:

said center mandrel defines a mandrel central opening therethrough;

said lower slip support is characterized by a valve housing defining a housing central opening therein and a housing port in communication with said housing central opening; and

further comprising a valve disposed in said housing central opening and providing communication between said port and said mandrel central opening when in an open position, said valve being disposed below a lower end of said mandrel.

62. The apparatus of claim 61 wherein upward movement of said valve is prevented by said mandrel.

63. The apparatus of claim 61 wherein said valve is a sliding valve defining a valve central opening therein and a valve port in communication with said valve central opening, wherein said valve port and said housing port are substantially aligned when said valve is in an open position.

64. The apparatus of claim 63 wherein said valve defines a seal groove therein; and

further comprising sealing means disposed in said seal groove for providing sealing engagement between said valve and said valve housing.

65. The apparatus of claim 63 wherein said valve housing defines a seal groove therein; and

further comprising sealing means disposed in said seal groove for providing sealing engagement between said valve and said valve housing.

66. The apparatus of claim 63 further comprising a bumper seal disposed below said valve for cushioning said valve as said valve is moved to said open position thereof.

67. The apparatus of claim 63 further comprising means for preventing relative rotation between said sliding valve and said valve housing.

... apparatus of claim 61 wherein said valve is positioned below said housing port when said valve is in said open position.

69. The apparatus of claim 61 further comprising a poppet type valve disposed in said valve housing for providing communication between said mandrel central opening and said housing port when said valve is in an open position.

70. The apparatus of claim 54 further comprising a bridging plug disposed in said mandrel and sealingly engaged therewith.

71. The apparatus of claim 58 wherein:

said upper slip support has a tapered shoulder on a lower end thereof;

said upper slips have a tapered shoulder on an upper end thereof adapted for sliding engagement with said shoulder on said upper slip support;

said lower slip support has a tapered shoulder on an upper end thereof: and

said lower slips have a tapered shoulder on a lower end thereof adapted for sliding engagement with said shoulder on said lower slip support.

72. The apparatus of claim 54 further comprising a plurality of inserts molded into each of said upper and lower slips, said inserts being made of a hardened material adapted for grippingly engaging said well bore.

73. A downhole apparatus for use in a well bore, said apparatus comprising:

a center mandrel made of a non-metallic material; and

slip means disposed on said mandrel for grippingly engaging said well bore when in a set position, said slip means comprising a slip wedge made of a non-metallic material.

74. A downhole apparatus for use in a well bore, said apparatus comprising a slip adapted for grippingly engaging the well bore, said slip being made of a non-metallic, non-elastomeric material.

75. A downhole apparatus for use in a well bore, said apparatus comprising:

a slip adapted for grippingly engaging the well bore, said slip being made of a non-metallic material; and

a hardened insert molded into said slip.

* * * * *

The United States of America

The Commissioner of Patents and Trademarks

Has received an application for a patent for a new and useful invention. The title and description of the invention are enclosed. The requirements of law have been complied with, and it has been determined that a patent on the invention shall be granted under the law.

Therefore, this

United States Patent

Grants to the person or persons having title to this patent the right to exclude others from making, using or selling the invention throughout the United States of America for the term of seventeen years from the date of this patent, subject to the payment of maintenance fees as provided by law.

Michael K. Kirk

Acting Commissioner of Patents and Trademarks

Sandra I. Morton

Attest

US005224540A

United States Patent [19]

Streich et al.

[11] **Patent Number:** 5,224,540

[45] **Date of Patent:** Jul. 6, 1993

[54] **DOWNHOLE TOOL APPARATUS WITH NON-METALLIC COMPONENTS AND METHODS OF DRILLING THEREOF**

[75] Inventors: Steven G. Streich; Donald F. Hushbeck; Kevin T. Berscheidt; Rick D. Jacobi, all of Duncan, Okla.

[73] Assignee: Halliburton Company, Duncan, Okla.

[21] Appl. No.: 883,619

[22] Filed: May 12, 1992

Related U.S. Application Data

[63] Continuation-in-part of Ser. No. 719,740, Jun. 21, 1991, which is a continuation-in-part of Ser. No. 515,019, Apr. 26, 1990, abandoned.

[51] Int. Cl.[5] E21B 33/129

[52] U.S. Cl. 166/118; 166/123; 166/128; 166/134; 166/382

[58] Field of Search 166/387, 376, 118, 135, 166/138, 179, 192

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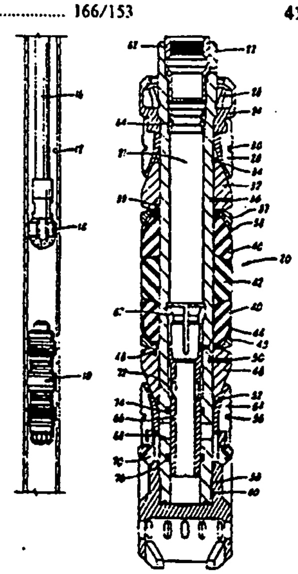
Primary Examiner—Stephen J. Novosad

Attorney, Agent, or Firm—James R. Duzah; Neal R. Kennedy

[57] **ABSTRACT**

A downhole tool apparatus and methods of drilling the apparatus. The apparatus may include, but is not limited to, packers and bridge plugs utilizing non-metallic slip components. The non-metallic material may include engineering grade plastics. In one embodiment, the slips are separate and held in place in an initial position around the slip wedge by a retainer ring. In another embodiment, the slips are integrally formed with a ring portion which holds the slips in the initial position around the wedge; in this embodiment, the ring portion is made of a fracturable non-metallic material which fractures during a setting operation to separate the slips. Methods of drilling out the apparatus without significant variations in the drilling speed and weight applied to the drill bit may be employed. Alternative drill bit types, such as polycrystalline diamond compact (PDC) bits may also be used.

41 Claims, 7 Drawing Sheets



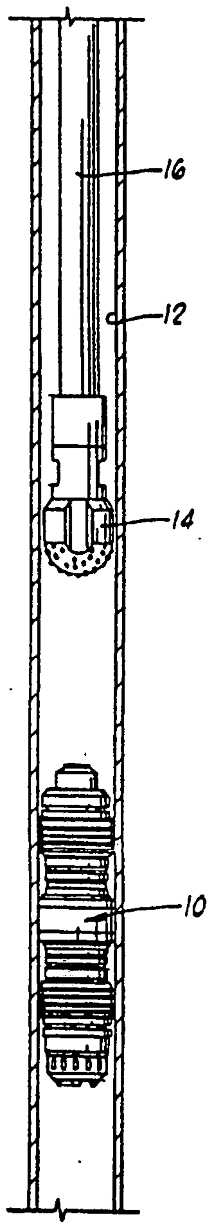

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FIG. 1

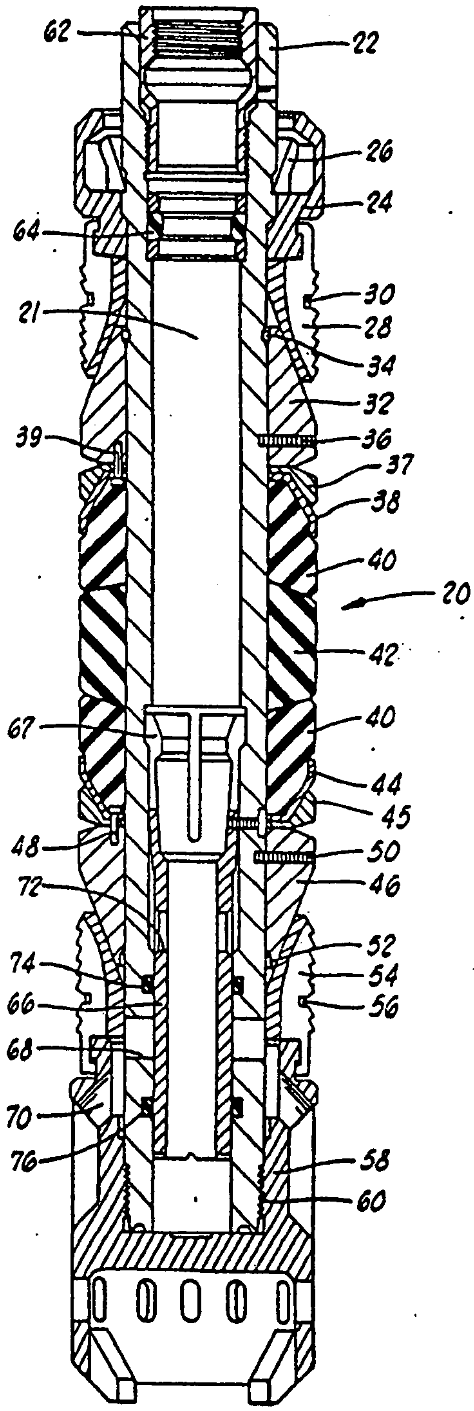
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FIG. 2

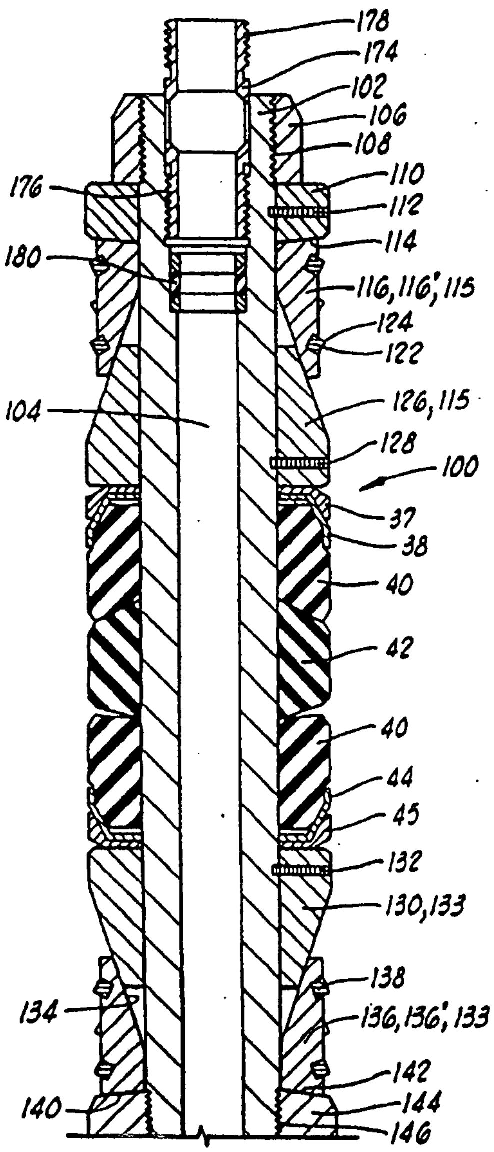
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FIG. 3A

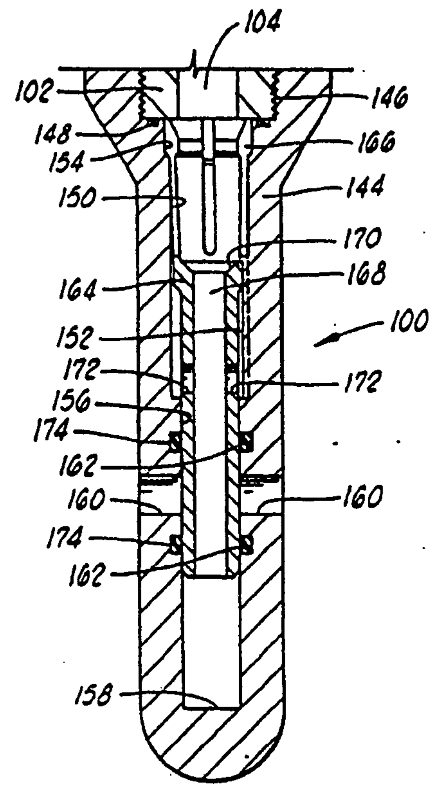
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FIG. 3B

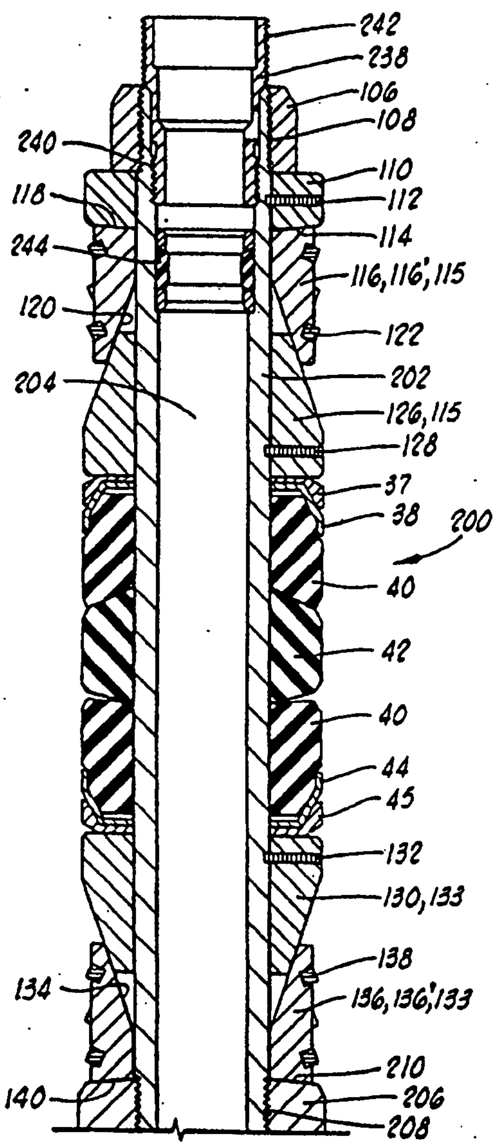
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FIG. 4A

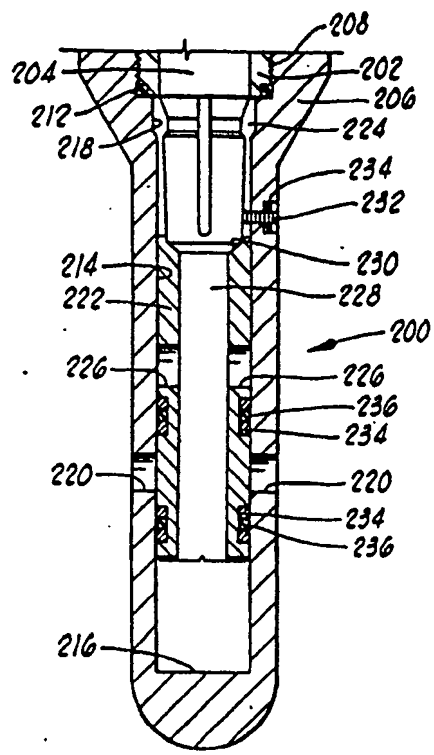
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FIG. 4B

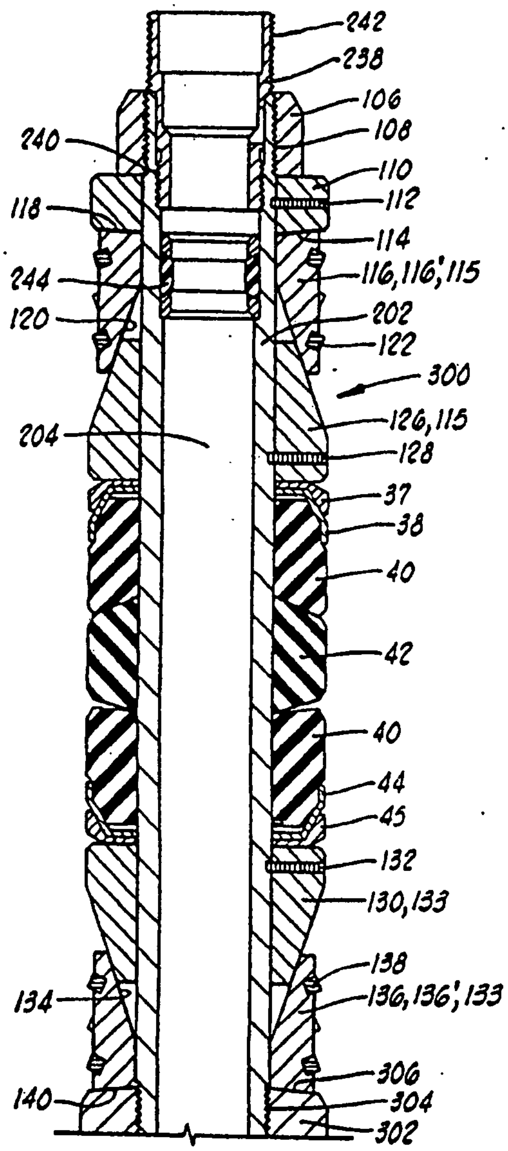
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FIG. 5A

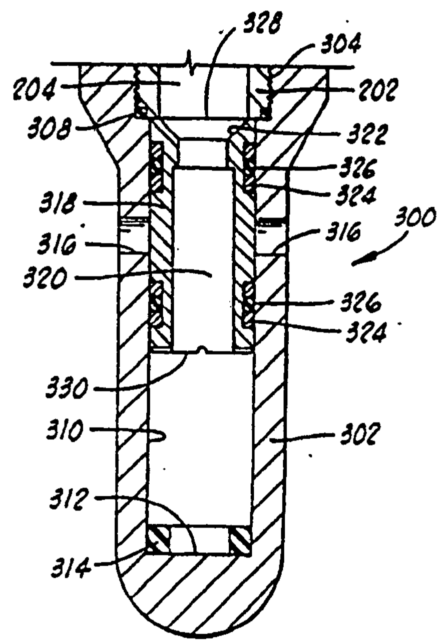
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FIG. 5B

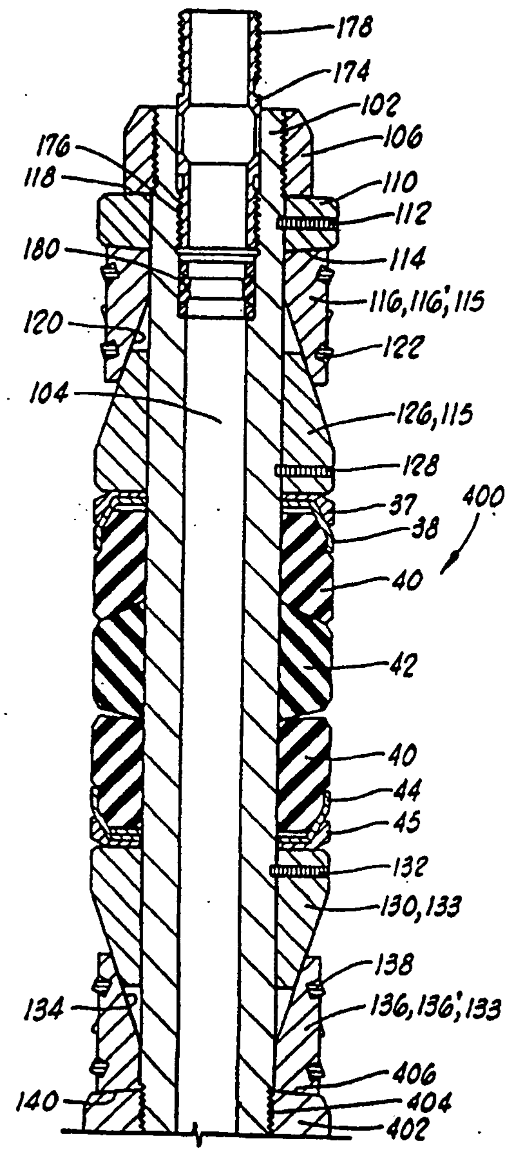
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FIG. 6A

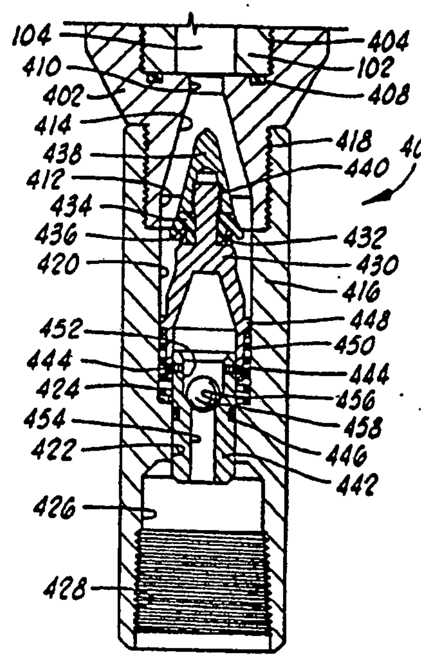
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FIG. 6B

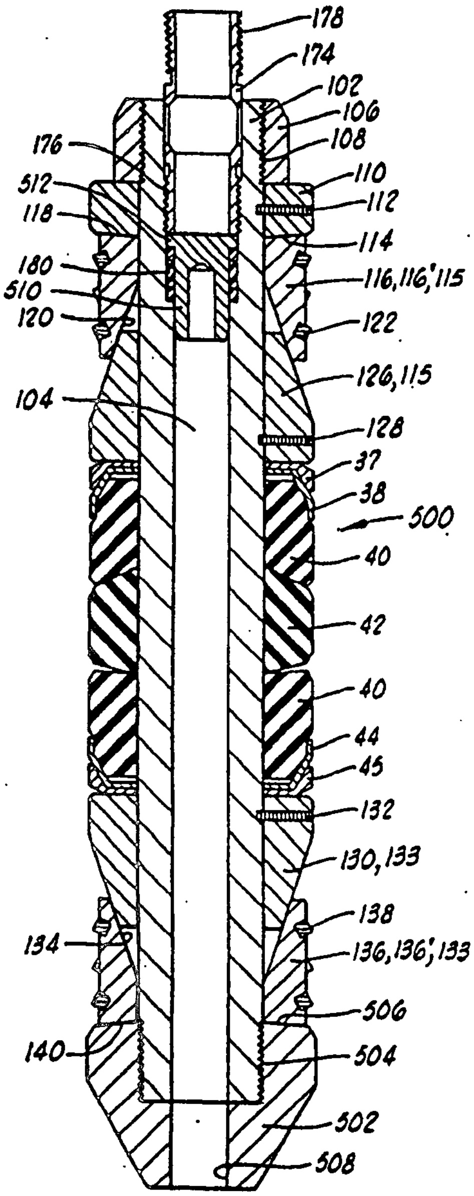
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FIG. 7

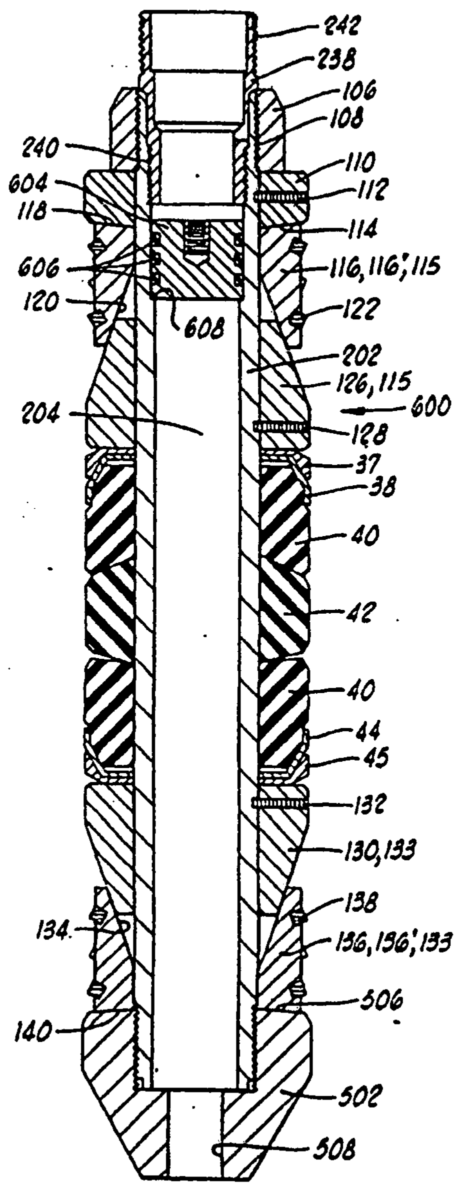
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FIG. 8

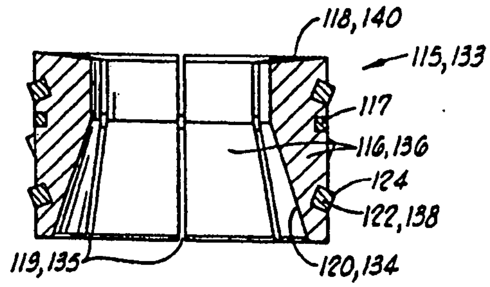


FIG. 9

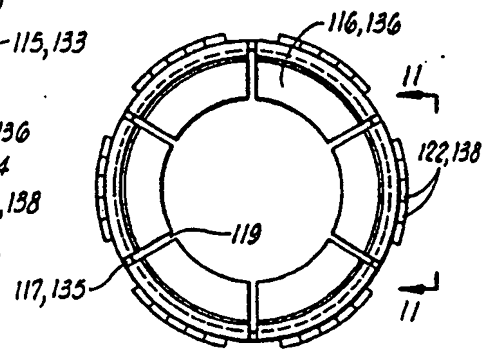


FIG. 10

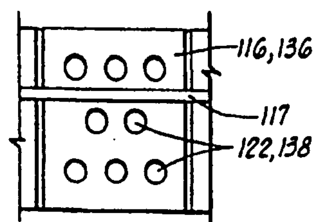


FIG. 11

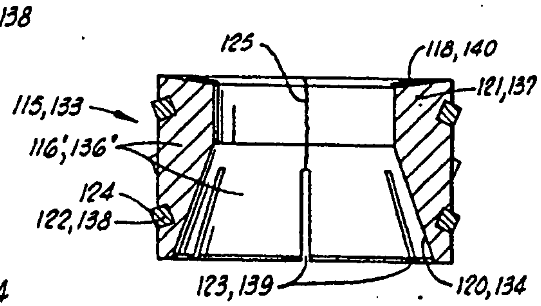


FIG. 12

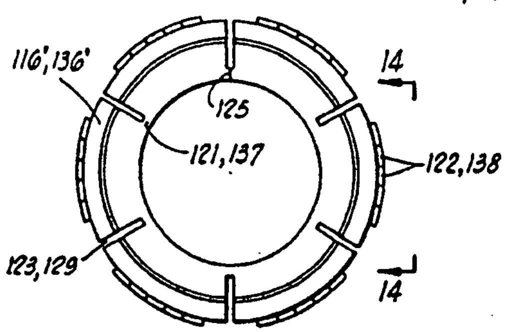


FIG. 13

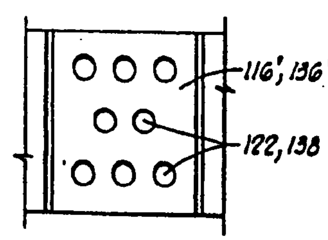


FIG. 14

DOWNHOLE TOOL APPARATUS WITH NON-METALLIC COMPONENTS AND METHODS OF DRILLING THEREOF

This application is a continuation-in-part of co-pending application Ser. No. 07/719,740, filed Jun. 21, 1991, which was a continuation-in-part of application Ser. No. 07/515,019, filed Apr. 26, 1990 and now abandoned.

BACKGROUND OF THE INVENTION

1. Field Of The Invention

This invention relates to downhole tools for use in well bores and methods of drilling such apparatus out of well bores, and more particularly, to such tools having drillable components, such as slips, therein made at least partially of non-metallic materials, such as engineering grade plastics.

2. Description Of The Prior Art

In the drilling or reworking of oil wells, a great variety of downhole tools are used. For example, but not by way of limitation, it is often desirable to seal tubing or other pipe in the casing of the well, such as when it is desired to pump cement or other slurry down tubing and force the slurry out into a formation. It then becomes necessary to seal the tubing with respect to the well casing and to prevent the fluid pressure of the slurry from lifting the tubing ou of the well. Packers and bridge plugs designed for these general purposes are well known in the art.

When it is desired to remove many of these downhole tools from a well bore, it is frequently simpler and less expensive to mill or drill them out rather than to implement a complex retrieving operation. In milling, a milling cutter is used to grind the packer or plug, for example, or at least the outer components thereof, out of the well bore. Milling is a relatively slow process, but it can be used on packers or bridge plugs having relatively hard components such as erosion-resistant hard steel. One such packer is disclosed in U.S. Pat. No. 4,151,875 to Sullaway, assigned to the assignee of the present invention and sold under the trademark EZ Disposal packer. Other downhole tools in addition to packers and bridge plugs may also be drilled out.

In drilling, a drill bit is used to cut and grind up the components of the downhole tool to remove it from the well bore. This is a much faster operation than milling, but requires the tool to be made out of materials which can be accommodated by the drill bit. Typically, soft and medium hardness cast iron are used on the pressure bearing components, along with some brass and aluminum items. Packers of this type include the Halliburton EZ Drill® and EZ Drill SV® squeeze packers.

The EZ Drill SV® squeeze packer, for example, includes a lock ring housing, upper slip wedge, lower slip wedge, and lower slip support made of soft cast iron. These components are mounted on a mandrel made of medium hardness cast iron. The EZ Drill® squeeze packer is similarly constructed. The Halliburton EZ Drill® bridge plug is also similar, except that it does not provide for fluid flow therethrough.

All of the above-mentioned packers are disclosed in Halliburton Services Sales and Service Catalog No. 43, pages 2561-2562, and the bridge plug is disclosed in the same catalog on pages 2556-2557.

The EZ Drill® packer and bridge plug and the EZ Drill SV® packer are designed for fast removal from the well bore by either rotary or cable tool drilling methods. Many of the components in these drillable packing devices are locked together to prevent their spinning while being drilled, and the harder slips are grooved so that they will be broken up in small pieces. Typically, standard "tri-cone" rotary drill bits are used which are rotated at speeds of about 75 to about 120 rpm. A load of about 5,000 to about 7,000 pounds of weight is applied to the bit for initial drilling and increased as necessary to drill out the remainder of the packer or bridge plug, depending upon its size. Drill collars may be used as required for weight and bit stabilization.

Such drillable devices have worked well and provide improved operating performance at relatively high temperature and pressures. The packers and plug mentioned above are designed to withstand pressures of about 10,000 psi and temperatures of about 425° F. after being set in the well bore. Such pressures and temperatures require the cast iron components previously discussed.

However, drilling out iron components requires certain techniques. Ideally, the operator employs variations in rotary speed and bit weight to help break up the metal parts and reestablish bit penetration should bit penetration cease while drilling. A phenomenon known as "bit tracking" can occur, wherein the drill bit stays on one path and no longer cuts into the downhole tool. When this happens, it is necessary to pick up the bit above the drilling surface and rapidly recontact the bit with the packer or plug and apply weight while continuing rotation. This aids in breaking up the established bit pattern and helps to reestablish bit penetration. If this procedure is used, there are rarely problems. However, operators may not apply these techniques or even recognize when bit tracking has occurred. The result is that drilling times are greatly increased because the bit merely wears against the surface of the downhole tool rather than cutting into it to break it up.

While cast iron components may be necessary for the high pressures and temperatures for which they are designed, it has been determined that many wells experience pressures less than 10,000 psi and temperatures less than 425° F. This includes most wells cemented. In fact, in the majority of wells, the pressure is less than about 5,000 psi, and the temperature is less than about 250° F. Thus, the heavy duty metal construction of the previous downhole tools, such as the packers and bridge plugs described above, is not necessary for many applications, and if cast iron components can be eliminated or minimized the potential drilling problems resulting from bit tracking might be avoided as well.

The downhole tool of the present invention solves this problem by providing an apparatus wherein at least some of the components, including slips and pressure bearing components, are made at least partially of non-metallic materials, such as engineering grade plastics. Such plastic components are much more easily drilled than cast iron, and new drilling methods may be employed which use alternative drill bits such as polycrystalline diamond compact bits, or the like, rather than standard tri-cone bits.

SUMMARY OF THE INVENTION

The downhole tool apparatus of the present invention utilizes non-metallic materials, such as engineering grade plastics, to reduce weight, to reduce manufacturing time and labor, to improve performance through

reducing frictional forces of sliding surfaces, to reduce costs and to improve drillability of the apparatus when drilling is required to remove the apparatus from the well bore. Primarily, in this disclosure, the downhole tool is characterized by well bore packing apparatus, but it is not intended that the invention be limited to such packing devices. The non-metallic components in the downhole tool apparatus also allow the use of alternative drilling techniques to those previously known.

In packing apparatus embodiments of the present invention, the apparatus may utilize the same general geometric configuration of previously known drillable packers and bridge plugs while replacing at least some of the metal components with non-metallic materials which can still withstand the pressures and temperatures exposed thereto in many well bore applications. In other embodiments of the present invention, the apparatus may comprise specific design changes to accommodate the advantages of plastic materials and also to allow for the reduced strengths thereof compared to metal components.

In one embodiment of the downhole tool, the invention comprises a center mandrel and slip means disposed on the mandrel for grippingly engaging the well bore when in a set position. In packing embodiments, the apparatus further comprises a packing means disposed on the mandrel for sealingly engaging the well bore when in a set position.

The slips means comprises a slip wedge positioned around the center mandrel, a plurality of slips disposed in an initial position around the mandrel and adjacent to the wedge, retaining means for holding the slips in the initial position, and a slip support on an opposite side of the slips from the wedge. In one embodiment, the slips are separate and the retaining means is characterized by a retaining band extending at least partially around the slips. In another embodiment, the retaining means is characterized by a ring portion integrally formed with the slips. This ring portion is fracturable during a setting operation, whereby the slips are separated so that they can be moved into gripping engagement with the well bore. Hardened inserts may be molded into the slips of either embodiment. The inserts may be metallic, such as hardened steel, or non-metallic, such as ceramic.

Any of the mandrel, slips, slip wedges or slip supports may be made of the non-metallic material, such as plastic. Specific plastics include nylon, phenolic materials and epoxy resins. The phenolic materials may further include any of Fiberite FM4056J, Fiberite FM4005 or Resinoid 1360. The plastic components may be molded or machined.

One preferred plastic material for at least some of these components is a glass reinforced phenolic resin having a tensile strength of about 18,000 psi and a compressive strength of about 40,000 psi, although the invention is not intended to be limited to this particular plastic or a plastic having these specific physical properties. The plastic materials are preferably selected such that the packing apparatus can withstand well pressures less than about 10,000 psi and temperatures less than about 425° F. In one preferred embodiment, but not by way of limitation, the plastic materials of the packing apparatus are selected such that the apparatus can withstand well pressures up to about 5,000 psi and temperatures up to about 250° F.

Most of the components of the slip means are subjected to substantially compressive loading when in a sealed operating position in the well bore, although some tensile loading may also be experienced. The center mandrel typically ha tensile loading applied thereto when setting the packer and when the packer is in its operating position.

One new method of the invention is a well bore process comprising the steps of positioning a downhole tool into engagement with the well bore; prior to the step of positioning, constructing the tool such that a component thereof is made of a non-metallic material; and then drilling the tool out of the well bore. The tool may be selected from the group consisting packers and bridge plugs, but is not limited to these devices.

The component made of non-metallic material, may be one of several such components. The components may be substantially subject to compressive loading. Such components in the tool may include lock ring housings, slips, slip wedges and slip supports. Some components, such as center mandrels of such tools may be substantially subjected to tensile loading.

In another embodiment, the step of drilling is carried out using a polycrystalline diamond compact bit. Regardless of the type of drill bit used, the process may further comprise the step of drilling using a drill bit without substantially varying the weight applied to the drill bit.

In another method of the invention, a well bore process comprises the steps of positioning and setting a packing device in the well bore, a portion of the device being made of engineering grade plastic; contacting the device with well fluids; and drilling out the device using a drill bit having no moving parts such as a polycrystalline diamond compact bit. This or a similar drill bit might have been previously used in drilling the well bore itself, so the process may be said to further comprise the step of, prior to the step of positioning and setting the packer, drilling at least a portion of the well bore using a drill bit such as a polycrystalline diamond compact bit.

In one preferred embodiment, the step of contacting the packer is at a pressure of less than about 5,000 psi and a temperature of less than about 250° F, although higher pressures and temperatures may also be encountered.

It is an important object of the invention to provide a downhole tool apparatus utilizing components, such as slip means, made at least partially of non-metallic materials and methods of drilling thereof.

It is another object of the invention to provide a well bore packing apparatus using slip means components made of engineering grade plastic.

It is a further object of the invention to provide a packing apparatus which may be drilled by alternate methods to those using standard rotary drill bits.

Additional objects and advantages of the invention will become apparent as the following detailed description of the preferred embodiments is read in conjunction with the drawings which illustrate such preferred embodiments.

BRIEF DESCRIPTION OF THE DRAWINGS

FIG. 1 generally illustrates the downhole tool of the present invention positioned in a well bore with a drill bit disposed thereabove.

FIG. 2 illustrates a cross section of one embodiment of a drillable packer made in accordance with the invention.

FIGS. 3A and 3B show a cross section of a second embodiment of a drillable packer.

FIGS. 4A and 4B show a third drillable packer embodiment.

FIGS. 5A and 5B illustrate a fourth embodiment of a drillable packer.

FIGS. 6A and 6B show a fifth drillable packer embodiment with a poppet valve therein.

FIG. 7 shows a cross section of one embodiment of a drillable bridge plug made in accordance with the present invention.

FIG. 8 illustrates a second embodiment of a drillable bridge plug.

FIG. 9 is a vertical cross section of one preferred embodiment of slips used in the drillable packer and bridge plug of the plug of the present invention.

FIG. 10 is an end view of the slips shown in FIG. 9.

FIG. 11 is an elevational view taken along lines 11—11 in FIG. 10.

FIG. 12 shows a vertical cross section of an alternate embodiment of slips used in the drillable packer and bridge plug of the present invention.

FIG. 13 is an end view of the slips of FIG. 12.

FIG. 14 shows an elevation as seen along lines 14—14 in FIG. 13.

DESCRIPTION OF THE PREFERRED EMBODIMENT

Referring now to the drawings, and more particularly to FIG. 1, the downhole tool apparatus of the present invention is shown and generally designated by the numeral 10. Apparatus 10, which may include, but is not limited to, packers, bridge plugs, or similar devices, is shown in an operating position in a well bore 12. Apparatus 10 can be set in this position by any manner known in the art such as setting on a tubing string or wire line. A drill bit 14 connected to the end of a tool or tubing string 16 is shown above apparatus 10 in a position to commence the drilling out of apparatus 10 from well bore 12. Methods of drilling will be further discussed herein.

First Packer Embodiment

Referring now to FIG. 2, the details of a first squeeze packer embodiment 20 of apparatus 10 will be described. The size and configuration of packer 20 is substantially the same as the previously mentioned prior art EZ Drill SV® squeeze packer. Packer 20 defines a generally central opening 21 therein.

Packer 20 comprises a center mandrel 22 on which most of the other components are mounted. A lock ring housing 24 is disposed around an upper end of mandrel 22 and generally encloses a lock ring 26.

Disposed below lock ring housing 24 and pivotally connected thereto are a plurality of upper slips 28 initially held in place by a retaining means, such as retaining band or ring 30. A generally conical upper slip wedge is disposed around mandrel 22 adjacent to upper slips 30. Upper slip wedge 32 is held in place on mandrel 22 by a wedge retaining ring 34 and a plurality of screws 36.

Adjacent to the lower end of upper slip wedge 32 is an upper back-up ring 37 and an upper packer shoe 38 connected to the upper slip wedge by a pin 39. Below upper packer shoe 38 are a pair of end packer elements 40 separated by center packer element 42. A lower packer shoe 44 and lower back-up ring 45 are disposed adjacent to the lowermost end packer element 40.

A generally conical lower slip wedge 46 is positioned around mandrel 22 adjacent to lower packer shoe 44, and a pin 48 connects the lower packer shoe to the lower slip wedge.

Lower slip wedge 46 is initially attached to mandrel 22 by a plurality of screws 50 and a wedge retaining ring 52 in a manner similar to that for upper slip wedge 32. A plurality of lower slips 54 are disposed adjacent to lower slip wedge 46 and are initially held in place by a retaining means, such as retaining band or ring 56. Lower slips 54 are pivotally connected to the upper end of a lower slip support 58. Mandrel 22 is attached to lower slip support 58 at threaded connection 60.

Disposed in mandrel 22 at the upper end thereof is a tension sleeve 62 below which is an internal seal 64. Tension sleeve 62 is adapted for connection with a setting tool (not shown) of a kind known in the art.

A collet-latch sliding valve 66 is slidably disposed in central opening 21 at the lower end of mandrel 22 adjacent to fluid ports 68 in the mandrel. Fluid ports 68 in mandrel 22 are in communication with fluid ports 70 in lower slip housing 58. The lower end of lower slip support 58 is closed below ports 70.

Sliding valve 66 defines a plurality of valve ports 72 which can be aligned with fluid ports 68 in mandrel 22 when sliding valve 66 is in an open position. Thus, fluid can flow through central opening 21.

On the upper end of sliding valve 66 are a plurality of collet fingers 67 which are adapted for latching and unlatching with a valve actuation tool (not shown) of a kind known in the art. This actuation tool is used to open and close sliding valve 66 as further discussed herein. As illustrated in FIG. 2, sliding valve 66 is in a closed position wherein fluid ports 68 are sealed by upper and lower valve seals 74 and 76.

In prior art drillable packers and bridge plugs of this type, mandrel 22 is made of a medium hardness cast iron, and lock ring housing 24, upper slip wedge 32, lower slip wedge 46 and lower slip support 58 are made of soft cast iron for drillability. Most of the other components are made of aluminum, brass or rubber which, of course, are relatively easy to drill. Prior art upper and lower slips 28 and 54 are made of hard cast iron, but are grooved so that they will easily be broken up in small pieces when contacted by the drill bit during a drilling operation.

As previously described, the soft cast iron construction of prior art lock ring housings, upper and lower slip wedges, and lower slip supports are adapted for relatively high pressure and temperature conditions, while a majority of well applications do not require a design for such conditions. Thus, the apparatus of the present invention, which is generally designed for pressures lower than 10,000 psi and temperatures lower than 425° F., utilizes engineering grade plastics for at least some of the components. For example, the apparatus may be designed for pressures up to about 5,000 psi and temperatures up to about 250° F., although the invention is not intended to be limited to these particular conditions.

In first packer embodiment 20, at least some of the previously soft cast iron components of the slip means, such as lock ring housing 24, upper and lower slip wedges 32 and 46 and lower slip support 58 are made of engineering grade plastics. In particular, upper and lower slip wedges 32 and 46 are subjected to substantially compressive loading. Since engineering grade plastics exhibit good strength in compression, they make excellent choices for use in components subjected to compressive loading. Lower slip support 58 is also subjected to substantially compressive loading and can

be made of engineering grade plastic when packer 20 is subjected to relative low pressures and temperatures.

Lock ring housing 24 is mostly in compression, but does exhibit some tensile loading. However, in most situations, this tensile loading is minimal, and lock ring housing 24 may also be made of an engineering grade plastic of substantially the same type as upper and lower slip wedges 32 and 46 and also lower slip housing 58.

Upper and lower slips 28 and 54 are illustrated in FIG. 2 as having a conventional configuration. However, non-metallic materials may be used, and thus upper and lower slips 28 and 54 may be made of plastic, for example, in some applications. Hardened inserts for gripping well bore 12 when packer 20 is set may be required as part of the plastic slips. New embodiments of slips utilizing such non-metallic materials will be described later herein.

Lock ring housing 24, upper slip wedge 32, lower slip wedge 46, and lower slip housing 58 comprise approximately 75% of the cast iron of the prior art squeeze packers. Thus, replacing these components with similar components made of engineering grade plastics will enhance the drillability of packer 20 and reduce the time and cost required therefor.

Mandrel 22 is subjected to tensile loading during setting and operation, and many plastics will not be acceptable materials therefor. However, some engineering plastics exhibit good tensile loading characteristics, so that construction of mandrel 22 from such plastics is possible. Reinforcements may be provided in the plastic resin as necessary.

Example

A first embodiment packer 20 was constructed in which upper slip wedge 32 and lower slip wedge 46 were constructed by molding the parts to size from a phenolic resin plastic with glass reinforcement. The specific material used was Fiberite 4056J manufactured by Fiberite Corporation of Winona, Minn. This material is classified by the manufacturer as a two stage phenolic with glass reinforcement. It has a tensile strength of 18,000 psi and a compressive strength of 40,000 psi.

The test packer 20 held to 8,500 psi without failure to wedges 32 and 46, more than sufficient for most well bore conditions.

Second Packer Embodiment

Referring now to FIGS. 3A and 3B, the details of a second squeeze packer embodiment 100 of packing apparatus 10 are shown. While first embodiment 20 incorporates the same configuration and general components as prior art packers made of metal, second packer embodiment 100 and the other embodiments described herein comprise specific design features to accommodate the benefits and problems of using non-metallic components, such as plastic.

Packer 100 comprises a center mandrel 102 on which most of the other components are mounted. Mandrel 102 may be described as a thick cross-sectional mandrel having a relatively thicker wall thickness than typical packer mandrels, including center mandrel 22 of first embodiment 20. A thick cross-sectional mandrel may be generally defined as one in which the central opening therethrough has a diameter less than about half of the outside diameter of the mandrel. That is, mandrel central opening 104 in central mandrel 102 has a diameter less than about half the outside of center mandrel 102. It is contemplated that a thick cross-sectional mandrel will be required if it is constructed from a material having relatively low physical properties. In particular, such materials may include phenolics and similar plastic materials.

An upper support 106 is attached to the upper end of center mandrel 102 at threaded connection 108. In an alternate embodiment, center mandrel 102 and upper support 106 are integrally formed and there is no threaded connection 108. A spacer ring or upper slip support 110 is disposed on the outside of mandrel 102 just below upper support 106. Spacer ring 110 is initially attached to center mandrel 102 by at least one shear pin 112. A downwardly and inwardly tapered shoulder 114 is defined on the lower side of spacer ring 110.

Disposed below spacer ring 110 is an upper slip means 115 comprising slips and a wedge. Referring now to FIGS. 9-11, a new embodiment of upper slip means 115 is characterized as comprising a plurality of separate non-metallic upper slips 116 held in place by a retaining means, such as retaining band or ring 117 extending at least partially around slips 116. Upper slips 116 may be held in place by other types of retaining means as well, such as pins. Slips 116 are preferably circumferentially spaced such that a longitudinally extending gap 119 is defined therebetween.

Each slip 116 has a downwardly and inwardly sloping shoulder 118 forming the upper end thereof. The taper of each shoulder 118 conforms to the taper of shoulder 114 on spacer ring 110, and slips 116 are adapted for sliding engagement with shoulder 114, as will be further described herein.

An upwardly and inwardly facing taper 120 is defined in the lower end of each slip 116. Each taper 120 generally faces the outside of center mandrel 102.

Referring now to FIGS. 12-14, an alternate embodiment of the slips of upper slip means 115 is shown. In this embodiment, a plurality of upper slips 116, are integrally formed at the upper ends thereof such that a ring portion 121 is formed. Ring portion 121 may be considered a retaining means for holding upper slips 116' in their initial position around center mandrel 102. The lower ends of slips 116' extend from ring portion 121 and are circumferentially separated by a plurality of longitudinally extending gaps 123. That is, in the second embodiment upper slip means 115 is a characterized as comprising a single piece molded or otherwise formed from a non-metallic material, such as plastic.

Each slip 116', like each slip 116, has downwardly and inwardly sloping shoulder 118 forming the upper end thereof and generally defined in ring portion 121. Again, the taper of each shoulder 118 conforms to the taper of shoulder 114 on spacer ring 110, and slips 116' are adapted for sliding engagement with shoulder 114, as will be further described herein.

As with slips 116, an upwardly and inwardly facing taper 120 is defined in the lower end of each slip 116'. As before, each taper 120 generally faces the outside of center mandrel 102.

A plurality of inserts or teeth 122 preferably are molded into upper slips 116 or 116'. Inserts 122 may have a generally cylindrical configuration and are positioned at an angle with respect to a central axis of packer 100. Thus, a radially outer edge 124 of each insert 122 protrudes from the corresponding upper slip 116 or 116'. Outer edge 124 is adapted for grippingly engaging well bore 12 when packer 100 is set. It is not intended that inserts 122 be limited to this cylindrical

shape or that they have a distinct outer edge 124. Various shapes of inserts may be used.

Inserts 122 can be made of any suitable hard material. For example, inserts 122 could be hardened steel or a non-metallic hardened material, such as ceramic.

Upper slip means 115 further comprises an upper slip wedge 126 which is disposed adjacent to upper slips 116 or 116' and engages taper 120 therein. Upper slip wedge 126 is initially attached to center mandrel 102 by one or more shear pins 128.

Below upper slip wedge 126 are upper back-up ring 37, upper packer shoe 38, end packer elements 40 separated by center packer element 42, lower packer shoe 44 and lower back-up ring 45 which are substantially the same as the corresponding components in first embodiment packer 20. Accordingly, the same reference numerals are used.

Below lower back-up ring 45 is a lower slip means 133 comprising a lower slip wedge 130 which is initially attached to center mandrel 102 by a shear pin 132. Preferably, lower slip wedge 130 is identical to upper slip wedge 126 except that it is positioned in the opposite direction.

In one new embodiment, lower slip means 133 is characterized as also comprising a plurality of separate non-metallic lower slips 136. Lower slips 136 are preferably identical to upper slips 116, except for a reversal of position, and are initially held in place by retaining means, such as retainer band or ring 117 which extends at least partially around slips 136. Other types of retainer means, such as pins, may also be used to hold slip lower slips 136 in place. Lower slips are preferably circumferentially spaced such that longitudinally extending gaps 135 are defined therebetween. See FIGS. 9-11.

In another embodiment, lower slip means 133 comprises a plurality of lower slips 136' which are integrally formed at the lower ends thereof such that a ring portion 137 is formed. Ring portion 137 may be considered a retaining means for holding lower slips 136' in their initial position around center mandrel 102. It will be seen that lower slips 136' are preferably identical to upper slips 116', except for a reversal in position. See FIGS. 12-14. At the upper ends thereof, slips 136' are circumferentially separated by plurality of longitudinally extending gaps 139.

A downwardly and inwardly facing inner taper 134 in each lower slip 136 or 136' is in engagement with lower slip wedge 130.

Lower slips 136 or 136' have inserts or teeth 138 molded therein which are preferably identical to inserts 122 in upper slips 116 or 116'.

Each lower slip 136 or 136' has a downwardly facing shoulder 140 defined in ring portion 137 which tapers upwardly and inwardly. Shoulders 140 are adapted for engagement with a corresponding shoulder 142 defining the upper end of a valve housing 144. Shoulder 142 also tapers upwardly and inwardly. Thus, valve housing 144 may also be considered a lower slip support 144.

Referring now also to FIG. 3B, valve housing 146 is attached to the lower end of center mandrel 102 at threaded connection 146. A sealing means, such as O-ring 148, provides sealing engagement between valve housing 144 and center mandrel 102.

Below the lower end of center mandrel 102, valve housing 104 defines a longitudinal opening 150 therein having a longitudinal rib 152 in the lower end thereof. At the upper end of opening 150 is an annular recess 154.

Below opening 150, valve housing 144 defines a housing central opening including a bore 156 therein having a closed lower end 158. A plurality of transverse ports 160 are defined through valve housing 144 and intersect bore 156. The wall thickness of valve housing 144 is thick enough to accommodate a pair of annular seal grooves 162 defined in bore 156 on opposite sides of ports 160.

Slidably disposed in valve housing 144 below center mandrel 102 is a sliding valve 164. Sliding valve 164 is the same as, or substantially similar to, sliding valve 66 in first embodiment packer 20. At the upper end of sliding valve 164 are a plurality of upwardly extending collet fingers 166 which initially engage recess 154 in valve housing 144. Sliding valve 164 is shown in an uppermost, closed position in FIG. 3B. It will be seen that the lower end of center mandrel 102 prevents further upward movement of sliding valve 164.

Sliding valve 164 defines a valve central opening 168 therethrough which is in communication with central opening 104 in center mandrel 102. A chamfered shoulder 170 is located at the upper end of valve central opening 168.

Sliding valve 164 defines a plurality of substantially transverse ports 172 therethrough which intersect valve central opening 168. As will be further discussed herein, ports 172 are adapted for alignment with ports 160 in valve housing 144 when sliding valve 164 is in a downward, open position thereof. Rib 152 fits between a pair of collet fingers 166 so that sliding valve 164 cannot rotate within valve housing 144, thus insuring proper alignment of ports 172 and 160. Rib 152 thus provides an alignment means.

A sealing means, such as O-ring 174, is disposed in each seal groove 162 and provides sealing engagement between sliding valve 164 and valve housing 144. It will thus be seen that when sliding valve 164 is moved downwardly to its open position, O-rings 174 seal on opposite sides of ports 172 in the sliding valve.

Referring again to FIG. 3A, a tension sleeve 174 is disposed in center mandrel 102 and attached thereto to threaded connection 176. Tension sleeve 174 has a threaded portion 178 which extends from center mandrel 102 and is adapted for connection to a standard setting tool (not shown) of a kind known in the art.

Below tension sleeve 174 is an internal seal 180 similar to internal seal 64 in first embodiment 20.

Third Packer Embodiment

Referring now to FIGS. 4A and 4B, a third squeeze packer embodiment of the present invention is shown and generally designated by the numeral 200. It will be clear to those skilled in the art that third embodiment 200 is similar to second packer embodiment 100 but has a couple of significant differences.

Packer 200 comprises a center mandrel 202. Unlike center mandrel 102 in second embodiment 100, center mandrel 202 is a thin cross-sectional mandrel. That is, it may be said that center mandrel 102 has a mandrel central opening 204 with a diameter greater than about half of the outside diameter of center mandrel 202. It is contemplated that thin cross-sectional mandrels, such as center mandrel 202, may be made of materials having relatively higher physical properties, such as epoxy resins.

The external components of third packer embodiment 200 which fit on the outside of center mandrel 202 are substantially identical to the outer components on second embodiment 100, and therefore the same reference numerals are shown in FIG. 4A. In a manner similar to second embodiment packer 100, center mandrel 202 and upper support 106 may be integrally formed so that there is no threaded connection 108.

The lower end of center mandrel 202 is attached to a valve housing 206 at threaded connection 208. On the upper end of valve housing 206 is an upwardly and inwardly tapered shoulder 210 against which shoulder 104 on lower slips 136 or 136' are slidably disposed. Thus, valve housing 206 may also be referred to as a lower slip support 206.

Referring now also to FIG. 4B, a sealing means, such as O-ring 212, provides sealing engagement between center mandrel 202 and valve housing 206.

Valve housing 206 defines a housing central opening including a bore 214 therein with a closed lower end 216. At the upper end of bore 214 is an annular recess 218. Valve housing 204 defines a plurality of substantially transverse ports 220 therethrough which intersect bore 214.

Slidably disposed in bore 214 in valve housing 206 is a sliding valve 222. At the upper end of sliding valve 222 are a plurality of collet fingers 224 which initially engage recess 218.

Sliding valve 222 defines a plurality of substantially transverse ports 226 therein which intersect a valve central opening 228 in the sliding valve. Valve central opening 228 is in communication with mandrel central opening 204 in center mandrel 202. At the upper end of central opening 228 is a chamfered shoulder 230.

As shown in FIG. 4B, sliding valve 222 is in an uppermost closed position. It will be seen that the lower end of center mandrel 202 prevents further upward movement of sliding valve 222. When sliding valve 222 is moved downwardly to an open position, ports 226 are substantially aligned with ports 220 in valve housing 206. An alignment means, such as an alignment bolt 232, extends from valve housing 206 inwardly between a pair of adjacent collet fingers 224. A sealing means, such as O-ring 234, provides sealing engagement between alignment bolt 232 and valve housing 206. Alignment bolt 234 prevents rotation of sliding valve 222 within valve housing 204 and insures proper alignment of ports 226 and 220 when sliding valve 222 is in its downwardmost, open position.

The wall thickness of sliding valve 222 is sufficient to accommodate a pair of spaced seal grooves 234 are defined in the outer surface of sliding valve 222, and as seen in FIG. 4B, seal grooves 234 are disposed on opposite sides of ports 220 when sliding valve 222 is in the open position shown. A sealing means, such as seal 236, is disposed in each groove 234 to provide sealing engagement between sliding valve 222 and bore 214 in valve housing 206.

Referring again to FIG. 4A, a tension sleeve 238 is attached to the upper end of center mandrel 202 at threaded connection 240. A threaded portion 242 of tension sleeve 238 extends upwardly from center mandrel 202 and is adapted for engagement with a setting apparatus (not shown) of a kind known in the art.

An internal seal 244 is disposed in the upper end of center mandrel 202 below tension sleeve 238.

Fourth Packer Embodiment

Referring now to FIGS. 5A and 5B, a fourth squeeze packer embodiment is shown and generally designated by the numeral 300. As illustrated, fourth embodiment 300 has the same center mandrel 202, and all of the components positioned on the outside of center mandrel 202 are identical to those in the second and third packer embodiments. Therefore, the same reference numerals are used for these components. Tension sleeve 238 and internal seal 244 positioned on the inside of the upper end of center mandrel 202 are also substantially identical to the corresponding components in third embodiment packer 200 and therefore shown with the same reference numerals.

The difference between fourth packer embodiment 300 and third packer embodiment 200 is that in the fourth embodiment shown in FIGS. 5A and 5B, the lower end of center mandrel 202 is attached to a different valve housing 302 at threaded connection 304. Shoulder 140 on each lower slip 136 or 136' slidingly engages an upwardly and inwardly tapered shoulder 306 on the top of valve housing 302. Thus, valve housing 302 may also be referred to as lower slip support 302.

Referring now to FIG. 5B, a sealing means, such as O-ring 308, provides sealing engagement between the lower end of center mandrel 202 and valve housing 302.

Valve housing 302 defines a housing central opening including a bore 310 therein with a closed lower end 312. A bumper seal 314 is disposed adjacent to end 312.

Valve housing 302 defines a plurality of substantially transverse ports 316 therethrough which intersect bore 310. A sliding valve 318 is disposed in bore 310, and is shown in an uppermost, closed position in FIG. 5B. It will be seen that the lower end of center mandrel 202 prevents upward movement of sliding valve 318. Sliding valve 318 defines a valve central opening 320 therethrough which is in communication with mandrel central opening 204 in center mandrel 202. At the upper end of valve central opening 320 in sliding valve 318 is an upwardly facing chamfered shoulder 322.

On the outer surface of sliding valve 318, a pair of spaced seal grooves 324 are defined. In the closed position shown in FIG. 5B, seal grooves 324 are on opposite sides of ports 316 in valve housing 302. A sealing means, such as seal 326, is disposed in each seal groove 324 and provides sealing engagement between sliding valve 318 and bore 310 in valve housing 302.

When sliding valve 318 is opened, as will be further described herein, the sliding valve 318 is moved downwardly such that upper end 328 thereof is below ports 316 in valve housing 302. Downward movement of sliding valve 318 is checked when lower end 330 thereof contacts bumper seal 314. Bumper seal 314 is made of a resilient material which cushions the impact of sliding valve 31 thereon.

Fifth Packer Embodiment

Referring now to FIGS. 6A and 6B, a fifth squeeze packer embodiment is shown and generally designated by the numeral 400. As illustrated, fifth packer embodiment 400 incorporates the same thick cross-sectional center mandrel 102 as does second packer embodiment 100 shown in FIGS. 3A and 3B. Also, the external components positioned on center mandrel 102 are the same as in the second, third and fourth packer embodiments, so the same reference numerals will be used.

Further, tension sleeve 174 and internal seal 180 in second embodiment 100 are also incorporated in fifth embodiment 400, and therefore these same reference numerals have also been used.

The difference between fifth packer embodiment 400 and second embodiment 100 is that the lower end of center mandrel 102 is attached to a lower slip support 402 at threaded connection 404. Shoulders 140 on lower slips 136 or 136' slidingly engage an upwardly and inwardly tapered shoulder 406 at the upper end of lower slip support 402.

Referring now to FIG. 6B, a sealing means, such as O-ring 408, provides sealing engagement between the lower end of center mandrel 102 and lower slip support 402.

Lower slip support 402 defines a first bore 410 therein and a larger second bore 412 spaced downwardly from the first bore. A tapered seat surface 414 extends between first bore 410 and second bore 412.

The lower end of lower support 402 is attached to a valve housing 416 at threaded connection 418. Valve housing 416 defines a first bore 420 and a smaller second bore 422 therein. An upwardly facing annular shoulder 424 extends between first bore 420 and second bore 422. Below second bore 422, valve housing 416 defines a third bore 426 therein with an internally threaded surface 428 forming a port at the lower end of the valve housing.

Disposed in first bore 420 in valve housing 416 is a valve body 430 with an upwardly facing annular shoulder 432 thereon. An elastomeric valve seal 434 and a valve spacer 436, which provides support for the valve seal, are positioned adjacent to shoulder 432 on valve body 430. A conical valve head 438 is positioned above valve seal 434 and is attached to valve body 430 at threaded connection 440. It will be seen by those skilled in the art that valve seal 434 is adapted for sealing engagement with seat surface 414 in lower slip support 402 when valve body 430 is moved upwardly.

The lower end of valve body 430 is connected to a valve holder 442 by one or more pins 444. Valve holder 442 is disposed in second bore 422 of valve housing 416. A sealing means, such as O-ring 446 provides sealing engagement between valve holder 442 and valve housing 416.

Above shoulder 424 in valve housing 416, valve body 430 has a radially outwardly extending flange 448 thereon. A biasing means, such as spring 450, is disposed between flange 448 and shoulder 424 for biasing valve body 430 upwardly with respect to valve housing 416.

Valve holder 442 defines a first bore 452 and a smaller second bore 454 therein with an upwardly facing chamfered shoulder 456 extending therebetween. A ball 458 is disposed in valve holder 442 and is adapted for engagement with shoulder 456.

First Bridge Plug Embodiment

Referring now to FIG. 7, a first bridge plug embodiment of the present invention is shown and generally designated by the numeral 500. First bridge plug embodiment 500 comprises the same center mandrel 102 and the external components positioned thereon as does the second packer embodiment 100. Therefore, the reference numerals for these components shown in FIG. 7 are the same as in FIG. 3A.

The lower end of center mandrel 102 in first bridge plug embodiment 500 is connected to a lower slip support 502 at threaded connection 504. An upwardly and inwardly tapered shoulder 506 on lower slip support 502 engages shoulders 140 on lower slips 136 or 136'. As with the other embodiments, slips 136 or 136' are adapted for sliding along shoulder 506.

Lower slip support 502 defines a bore 508 therein which is in communication with mandrel central opening 104 in center mandrel 102.

A bridging plug 510 is disposed in the upper portion of mandrel central opening 104 in center mandrel 102 and is sealingly engaged with internal seal 180. A radially outwardly extending flange 512 prevents bridging plug 510 from moving downwardly through center mandrel 102.

Above bridging plug 510 is tension sleeve 174, previously described for second packer embodiment 100.

Second Bridge Plug Embodiment

Referring now to FIG. 8, a second bridge plug embodiment of the present invention is shown and generally designated by the numeral 600. Second bridge plug embodiment 600 uses the same thin cross-sectional mandrel 202 as does third packer embodiment 200 shown in FIG. 4A. Also, the external components positioned on center mandrel 202 are the same as previously described, so the same reference numerals are used in FIG. 8.

In second bridge plug embodiment 600, the lower end of center mandrel 202 is attached to the same lower slip support 502 as first bridge plug embodiment 500 at threaded connection 602. It will be seen that bore 508 in lower slip support 502 is in communication with mandrel central opening 204 in center mandrel 202.

A bridging plug 604 is positioned in the upper end of mandrel central opening 204 in center mandrel 202. A shoulder 608 in central opening 204 prevents downward movement of bridging plug 604. A sealing means, such as a plurality of O-rings 606, provide sealing engagement between bridging plug 604 and center mandrel 202.

Tension sleeve 238, previously described, is positioned above bridging plug 604.

Setting And Operation Of The Apparatus

Downhole tool apparatus 10 is positioned in well bore 12 and set into engagement therewith in a manner similar to prior art devices made with metallic components. For example, a prior art apparatus and setting thereof is disclosed in the above-referenced U.S. Pat. No. 4,151,875 to Sullaway. This patent is incorporated herein by reference.

For first packer embodiment 20, the setting tool pulls upwardly on tension sleeve 62, and thereby on mandrel 22, while holding lock ring housing 24. The lock ring housing is thus moved relatively downwardly along mandrel 22 which forces upper slips 28 outwardly and shears screws 36, pushing upper slip wedge 32 downwardly against packer elements 40 and 42. Screws 50 are also sheared and lower slip wedge 46 is pushed downwardly toward lower slip support 58 to force lower slips 54 outwardly. Eventually, upper slips 28 and lower slips 54 are placed in gripping engagement with well bore 12 and packer elements 40 and 42 are in sealing engagement with the well bore. The action of upper slips 28 and 54 prevent packer 20 from being unset. As will be seen by those skilled in the art, pressure below packer 20 cannot force the packer out of well bore 12, but instead, causes it to be even more tightly engaged.

Eventually, in the setting operation, tension sleeve 62 is sheared, so the setting tool may be removed from the well bore.

The setting of second packer embodiment 100, third packer embodiment 200, fourth packer embodiment 300, fifth packer embodiment 400, first bridge plug embodiment 500 and second bridge plug embodiment 600 is similar to that for first packer embodiment 20. The setting tool is attached to either tension sleeve 174 or 238. During setting, the setting tool pushes downwardly on upper slip support 110, thereby shearing shear pin 112. Upper slips 116 or 116' are moved downwardly with respect to upper slip wedge 126. Tapers 120 in upper slips 116 or 116' slide along upper slip wedge 126, and shoulders 118 on upper slips 116 or 116' slide along shoulder 114 on upper slip support 110. Thus, upper slips 116 or 116' are forced radially outwardly with respect to center mandrel 102 or 202.

As this outward force is applied to slips 116 in the embodiment of FIGS. 9-11, retaining band 117 is broken, and slips 116 are freed to move radially outwardly such that edges 124 of inserts 122 grippingly well bore 12.

As the outward force is applied to alternate embodiment slips 116' (FIGS. 12-14), ring portion 121 will fracture, probably starting at the base of each gap 123. A typical fracture line 125 is shown in FIGS. 12 and 13. In other words, slips 116' separate and are freed to move radially outwardly such that edges 124 of inserts 122 grippingly engage well bore 12.

Also during the setting operation, upper slip wedge 126 is forced downwardly, shearing shear pin 128. This in turn causes packer elements 40 and 42 to be squeezed outwardly into sealing engagement with the well bore.

The lifting on center mandrel 102 or 202 causes the lower slip support (valve housing 144 in first packer embodiment 100, valve housing 206 in second packer embodiment 200, valve housing 302 in fourth packer embodiment 300, lower slip support 402 in fifth packer embodiment 400, and lower slip support 502 in first bridge plug embodiment 500 and second bridge plug embodiment 600) to be moved up and lower slips 136 or 136' to be moved upwardly with respect to lower slip wedge 130. Tapers 134 in lower slips 136 or 136' slide along lower slip wedge 130, and shoulders 140 on lower slips 136 or 136' slide along the corresponding shoulder 142, 210, 306, 406, or 506. Thus, lower slips 136 or 136' are forced radially outwardly with respect to center mandrel 102 or 202.

As this force is applied to slips 136 in the embodiment of FIGS. 9-11, retaining band 117 is broken, and slips 136 are freed to move radially outwardly such that edges 124 of inserts 138 grippingly engage well bore 12.

As the outward force is applied to alternate embodiment slips 136' (FIGS. 12-14), ring portion 137 will fracture, probably starting at the base of each gap 139. A typical fracture line 125 is shown in FIGS. 12 and 13. In other words, slips 136' separate and are freed to move radially outwardly such that edges 124 of inserts 138 grippingly engage well bore 12.

Also during the setting operation, lower slip wedge 130 is forced upwardly, shearing shear pin 132, to provide additional squeezing force on packer elements 40 and 42.

The engagement of inserts 122 in upper slips 116 or 116' and inserts 138 in lower slips 136 or 136' with well bore 12 prevent packers 100, 200, 300, 400 and bridge plugs 500, 600 from coming unset.

Once any of packers 20, 100, 200, 300, 400 are set, the valves therein may be actuated in a manner known in the art. Sliding valve 164 in second packer embodiment 126, and sliding valve 22 in third packer embodiment 200 are set in a similar, if not identical manner. Sliding valve 318 in fourth packer embodiment 300 is also set in a similar manner, but does not utilize collets, nor is alignment of sliding valve 318 with respect to ports 316 in valve housing 302 important. Sliding valve 318 is simply moved below ports 316 to open the valve. Bumper seal 314 cushions the downward movement of sliding valve 318, thereby minimizing the possibility of damage to sliding valve 318 or valve housing 302 during an opening operation.

In fifth packer embodiment 400, the valve assembly comprising valve body 432, valve seal 434, valve spacer 436, valve head 438 and valve holder 442 is operated in a manner substantially identical to that of the Halliburton EZ Drill® squeeze packer of the prior art.

Drilling Out The Packer Apparatus

Drilling out any embodiment of downhole tool 10 may be carried out by using a standard drill bit at the end of tubing string 16. Cable tool drilling may also be used. With a standard "tri-cone" drill bit, the drilling operation is similar to that of the prior art except that variations in rotary speed and bit weight are not critical because the non-metallic materials are considerably softer than prior art cast iron, thus making tool 10 much easier to drill out. This greatly simplifies the drilling operation and reduces the cost and time thereof.

In addition to standard tri-cone drill bits, and particularly if tool 10 is constructed utilizing engineering grade plastics for the mandrel as well as for slip wedges, slips, slip supports and housings, alternate types of drill bits may be used which would be impossible for tools constructed substantially of cast iron. For example, polycrystalline diamond compact (PDC) bits may be used. Drill bit 14 in FIG. 1 is illustrated as a PDC bit. Such drill bits have the advantage of having no moving parts which can jam up. Also, if the well bore itself was drilled with a PDC bit, it is not necessary to replace it with another or different type bit in order to drill out tool 10.

While specific squeeze packer and bridge plug configurations of packing apparatus 10 has been described herein, it will be understood by those skilled in the art that other tools may also be constructed utilizing components selected of non-metallic materials, such as engineering grade plastics.

Additionally, components of the various packer embodiments may be interchanged. For example, thick cross-sectional center mandrel 102 may be used with valve housing 206 in second packer embodiment 200 or valve housing 302 in fourth packer embodiment 300. Similarly, thin cross-sectional center mandrel 202 could be used with valve body 144 in second packer embodiment 100 or lower slip support 402 and valve housing 416 in fifth packer embodiment 400. The intent of the invention is to provide devices of flexible design in which a variety of configurations may be used.

It will be seen, therefore, that the downhole tool packer apparatus and methods of drilling thereof of the present invention are well adapted to carry out the ends and advantages mentioned as well as those inherent therein. While presently preferred embodiments of the apparatus and various drilling methods have been discussed for the purposes of this disclosure, numerous

changes in the arrangement and construction of parts and the steps of the methods may be made by those skilled in the art. In particular, the invention is not intended to be limited to squeeze packers or bridge plugs. All such changes are encompassed within the scope and spirit of the appended claims.

What is claimed is:

1. A downhole apparatus for use in a well bore, said apparatus comprising:

a center mandrel; and

slip means disposed on said mandrel for grippingly engaging said well bore when in a set position, said slip means being at least partially made of a non-metallic material.

2. The apparatus of claim 1 characterized as a packing apparatus and further comprising packing means disposed on said mandrel for sealingly engaging said well bore when in a set position.

3. The apparatus of claim 2 wherein said slip means is an upper slip means disposed above said packing means and further comprising a lower slip means disposed below said packing means, said lower slip means being at least partially made of a non-metallic material.

4. The apparatus of claim 1 wherein said slip means comprises a slip support made of a non-metallic material.

5. The apparatus of claim 1 wherein said slip means comprises a slip wedge made of non-metallic material.

6. The apparatus of claim 1 wherein said slip means comprises:

a plurality of non-metallic slips disposed in an initial position around said mandrel; and

retaining means for holding said slips in said initial position.

7. The apparatus of claim 6 wherein said retaining means is characterized by a retaining band extending at least partially around said slips.

8. The apparatus of claim 6 wherein said retaining means comprises a non-metallic ring portion integrally formed with said slips and being fracturable during a setting operation, whereby said slips are separated.

9. The apparatus of claim 8 wherein said slips define a plurality of gaps therebetween adjacent to an end of said slips.

10. The apparatus of claim 6 further comprising a plurality of hardened inserts molded into said slips

11. The apparatus of claim 10 wherein said inserts are steel.

12. The apparatus of claim 10 wherein said inserts are made of a non-metallic material.

13. The apparatus of claim 12 wherein said inserts are made of a ceramic material.

14. The apparatus of claim 1 wherein said non-metallic material is an engineering grade plastic.

15. The apparatus of claim 14 wherein said plastic is nylon.

16. The apparatus of claim 14 wherein said plastic is a phenolic material.

17. The apparatus of claim 16 wherein said phenolic material is one of Fiberite FM4056J, Fiberite FM4005 and Resinoid 1360.

18. The apparatus of claim 14 wherein said plastic is an epoxy resin.

19. A downhole apparatus for use in a well bore, said apparatus comprising:

a center mandrel;

a slip wedge disposed around said mandrel;

a plurality of separate non-metallic slips disposed around said mandrel adjacent to said wedge; and

retaining means for retaining said slips in an initial position out of engagement with the well bore.

20. The apparatus of claim 19 wherein said wedge is made of a non-metallic material.

21. The apparatus of claim 19 wherein said slips are made of engineering grade plastic.

22. The apparatus of claim 21 wherein said plastic is nylon.

23. The apparatus of claim 21 wherein said plastic is a phenolic material.

24. The apparatus of claim 21 wherein said phenolic material is Fiberite FM4056J.

25. The apparatus of claim 21 wherein said plastic is an epoxy resin.

26. The apparatus of claim 19 further comprising a plurality of inserts molded into said slips for grippingly engaging the well bore when in a set position.

27. The apparatus of claim 26 wherein said inserts are hardened steel.

28. The apparatus of claim 26 wherein said inserts are made of a non-metallic material.

29. The apparatus of claim 28 wherein said inserts are made of a ceramic material.

30. A downhole apparatus for use in a well bore, said apparatus comprising:

a center mandrel;

a slip wedge disposed around said mandrel;

a plurality of non-metallic slips disposed around said mandrel adjacent to said wedge; and

a non-metallic ring integrally formed at an end of each of said slips and adapted for holding said slips in an initial position out of engagement with the well bore.

31. The apparatus of claim 30 wherein said wedge is made of a non-metallic material.

32. The apparatus of claim 31 wherein said slips define a plurality of longitudinally extending gaps therebetween adjacent to an opposite end of said slips from said ring.

33. The apparatus of claim 30 wherein said ring is made of a fracturable engineering grade plastic.

34. The apparatus of claim 33 wherein said plastic is nylon.

35. The apparatus of claim 33 wherein said plastic is a phenolic material.

36. The apparatus of claim 33 wherein said phenolic material is Fiberite FM4056J.

37. The apparatus of claim 33 wherein said plastic is an epoxy resin.

38. The apparatus of claim 30 further comprising a plurality of inserts molded into said slips for grippingly engaging the well bore when in a set position.

39. The apparatus of claim 38 wherein said inserts are hardened steel.

40. The apparatus of claim 38 wherein said inserts are made of a non-metallic material.

41. The apparatus of claim 38 wherein said inserts are made of a ceramic material.

* * * * *

Weatherford
Completion Systems

(BP8 and BP10)

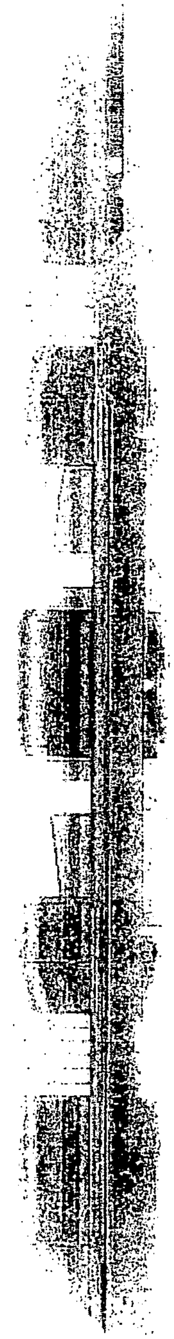
The Weatherford FracGuard™ Composite Bridge Plug provides a means to temporarily plug a well or to isolate zones during high pressure stimulation. The composite body and component construction allow for rapid drill up using common workover type bits. The lightweight cuttings produced lift easily and do not pile up on plugs below in multiple plug applications.

The Weatherford FracGuard™ Composite Bridge Plugs are available in standard and High Pressure / High Temperature (HP/HT) versions. The BP8 standard bridge plug is rated to 8,000 psi differential pressure from above up to 250°F and the BP10 HP/HT version is rated to 10,000 psi differential pressure from above at 350°F.

Both the Standard and the HP/HT Bridge Plugs may be run on tubing, drill pipe, coiled tubing, or on wireline using conventional bridge plug setting equipment.

- Single or multiple zone stimulation
- Vertical, deviated, horizontal or multilateral wellbores
- Temporary well plugging
- Underbalanced, multiple zone completions

- Holds full differential pressure from above and below
- Multiple plugs may be run to isolate a series of zones
- Allows underbalanced drill out of multiple plugs which protects sensitive formations
- Drills out quickly with conventional tri-cone or junk mill bits which saves time
- Beveled bottom prevents body from spinning which speeds drill up times
- Lightweight cuttings lift easily and minimize plugging of surface equipment



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Weatherford Completion Systems
www.weatherford.com

W000021

Weatherford

Completion Systems

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(FP8 and FP10)

The Weatherford FracGuard™ Composite Frac Plug provides a means isolate a lower zone from an upper zone undergoing a high pressure stimulation. The integral check ball holds differential pressure from above but allows flow back from below the plug.

The Weatherford FracGuard™ Composite Frac Plugs are available in standard and High Pressure / High Temperature (HP/HT) versions. The FP8 standard bridge plug is rated to 8,000 psi differential pressure from above up to 250°F and the FP10 HP/HT version is rated to 10,000 psi differential pressure from above at 350°F.

Both the Standard and the HP/HT Frac Plugs can be run on tubing, drill pipe, coiled tubing, or on wireline using conventional bridge plug setting equipment.

- Single or multiple zone stimulation
- Vertical, deviated, horizontal or multilateral wellbores
- Underbalanced, multiple zone completions

- Holds full differential pressure from above and allows flow through the mandrel from below
- Multiple plugs may be run to isolate a series of zones
- Drills out quickly with conventional tri-cone or junk-mill bits which saves time
- Beveled bottom prevents body from spinning which speeds drill up times
- Lightweight cuttings lift easily and minimize plugging of surface equipment
- Ball is pinned in place in the plug to eliminate possible seating problems associated with floating balls

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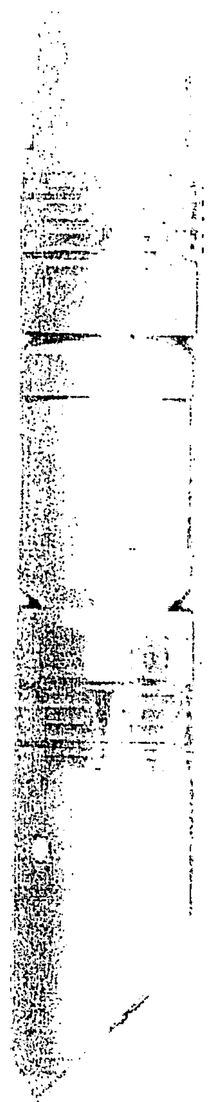
BJ PYTHON™ COMPOSITE BRIDGE PLUG

Product Information

TOOLS



Description

The BJ Services Composite Bridge Plug (called Python) is constructed of high-tech composite materials, which are easily drillable with a coiled tubing unit.

Features and Benefits

Rapid Drill Out
Two tapered mating surfaces at the top and bottom of each plug rotationally lock plug remnants, promoting ultra-fast drill out.

High Temperature Rating
The tool is designed to operate in 4½", 9.5-15.1# casing at 350°F with 10,000 psi differential pressure.

Slip Design
The slip design combines good bite into the casing with easy drillability.

Standard Deployment
The tool is run on the Baker #10 Wireline Pressure Setting Assembly.

Patent Pending

3/20/01

BJ SERVICES COMPANY

BJ000001

BURRIS DECLARATION
JUNE 13, 2002
EXHIBIT D

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BJ000004

Python™
Composite Bridge Plug

Presented by

Doug Lehr

BJ Services Company

get on ... with BJ

BJ 4 1/2" Python™ Composite Plug

- Design Requirements
  - 350° F x 10,000 ΔP without cement on top
  - CT removal not to exceed 45 minutes
  - Design for 4-1/2" 9.5 - 15.1 ppf
  - Design for wire line conveyance
  - Avoid use of adhesives on part connections

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BJ 4 1/2" Python™ Composite Plug

- Design Challenges
  - Reliable/fast removal
  - 350° F & 10,000 ΔP operation

BJ 4 1/2" Python™ Composite Plug

- How Did We "Rise to the Challenge"?
  - "Out of box thinking"
  - Novel slip design
  - Use of fiber-reinforced plastics - space age materials

get on ... with BJ

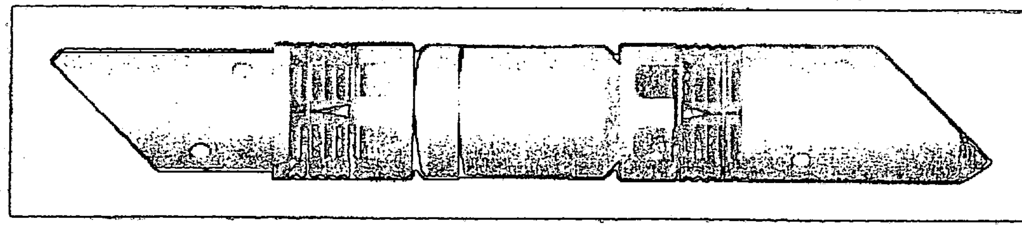
BJ 4 1/2" Python™ Composite Plug

What was the Result?

Python™ Composite Bridge Plug

BJ 4 1/2" Python™ Composite Plug

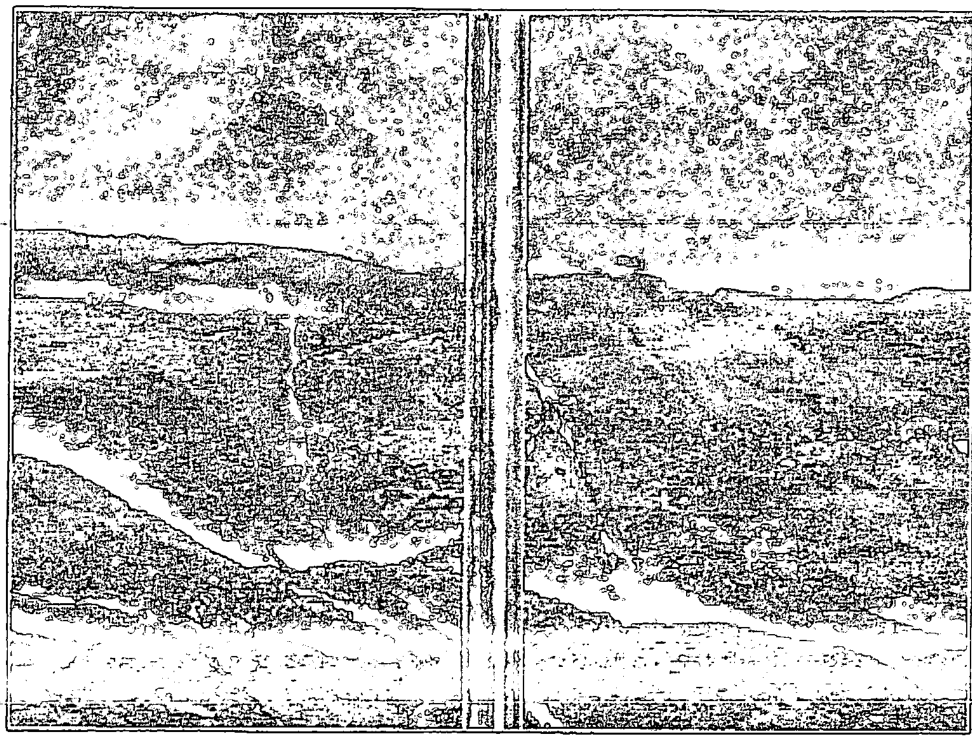
- A Plug Designed for:
  - Reliable Drill Out
  - High Pressure Performance
  - Patent Pending



get on board with BJ

Due to its large size, the Video clip on the next slide is not available on this website. If you are interested in viewing this clip, please contact your local BJ Representative OR send us a request by clicking the GO BJ icon. In either case, please provide us the title of this presentation and the name(s) of the presenter(s).

BJ 4 1/2" Python™ Composite Plug



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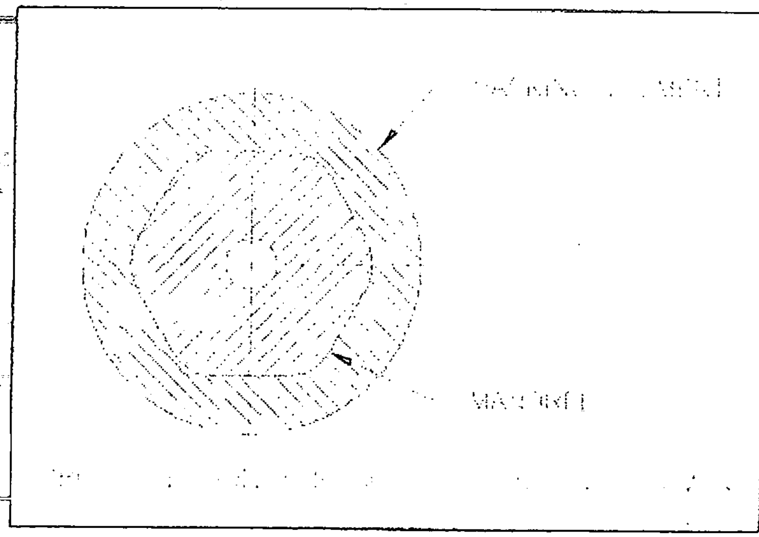
get on ... with BJ

BJ 4 1/2" Python™ Composite Plug

- Materials of Construction
  - High temperature fiber reinforced plastics
  - Novel slip design - cast iron, hardened wickers - small pieces circulate out easily
  - HNBR elastomers, far longer lifetime vs traditional nitrile.
  - NO ADHESIVES USED TO CONNECT PARTS TOGETHER !

BJ 4 1/2" Python™ Composite Plug

Intrinsic rotational lock among all parts



BJ 4 1/2" Python™ Composite Plug

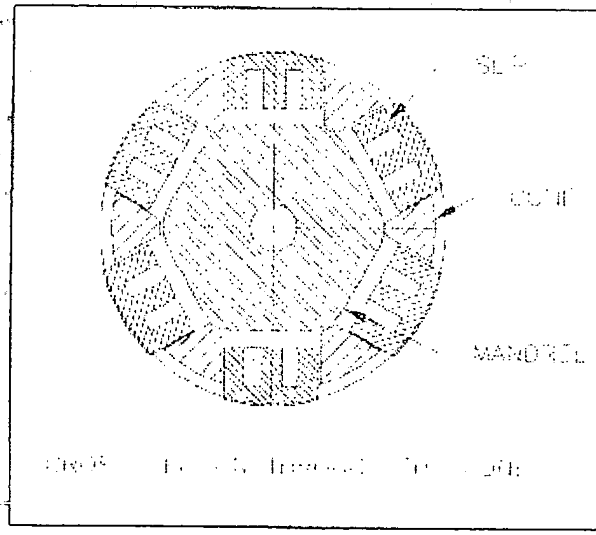
- A Thoroughly Tested Product!
  - Over 40 Laboratory Tests
  - *1,500 man-hours of testing*

get onboard with BJ

BJ 4 1/2" Python™ Composite Plug

Novel slip design, small pieces circulate out easily!

Slips are rotationally locked to the cone at all times



Use of internal voids in slips results in many small pieces during removal

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BJ 4 1/2" Python™ Composite Plug

- Why 40 tests?
  - pressure
  - temperature
  - tension
  - setting tests, hydraulic and electric line
  - 3 sets of drill out tests

BJ 4 1/2" Python™ Composite Plug

- Full scale tests in 9.5 ppf -15.1 ppf
- Electric line tests in 9.5 ppf -15.1 ppf
- Most tests conducted at 350° F &10,000 ΔP
- 5 day "long term" test at 250° F & 5,000 ΔP
- Drop rate testing @ 300 foot per minute
- Release stud testing

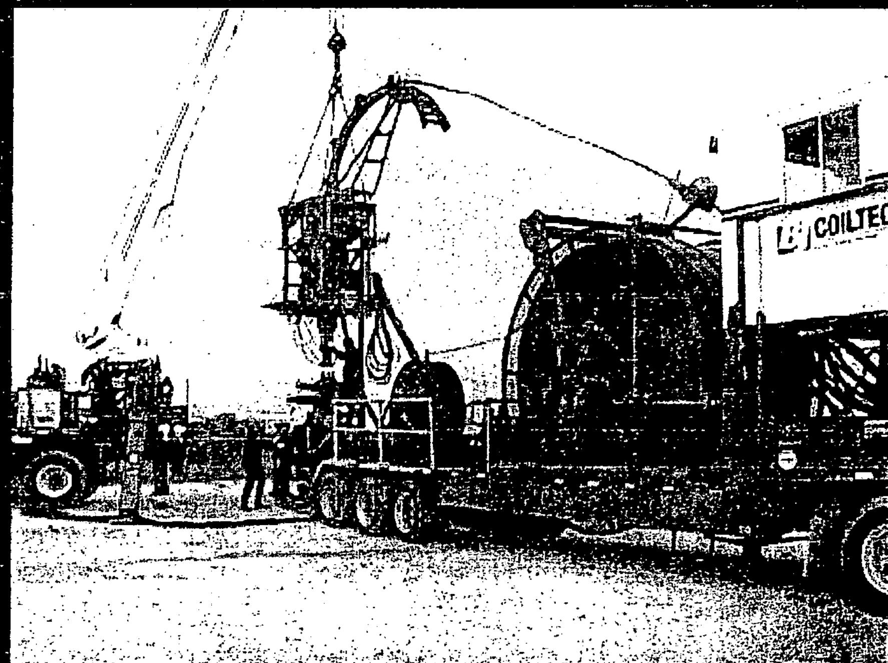
get OFF with BJ

BJ 4 1/2" Python™ Composite Plug

What about CT Removal?

get (BJ) with BJ

4-1/2" Python™ Removal Testing



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4-1/2" Python™ Removal Testing

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BJ000022

4-1/2" Python™ Removal Testing

- Summary of Simulated CT Mill Out tests:
  - 5 blade carbide junk mill
  - 2 BPM flow rate with fresh water
  - virtually no WOB due to shallow depth
  - 45 minutes for top plug
  - 60 minutes for bottom plug
  - Comprehensive mill out instructions available

BJ 4 1/2" Python™ Composite Plug

- Summary...
  - At 350° F, the Python far exceeds competitive temperature ratings
  - Cement NOT NEEDED to operate with integrity
  - CT Removal - very reliable due to intrinsically locked design - small pieces circulate out easily!
  - NO ADHESIVES USED TO CONNECT PARTS
  - The 4-1/2" Python covers 9.5 - 15.1 ppf

get ON with BJ

Questions?

Python™
Composite Bridge Plug

get (l)(l) with

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NORTHERN DISTRICT OF TEXAS
FILED
JUN 27 2002
CLERK, U.S. DISTRICT COURT
By ____________
Deputy

IN THE UNITED STATES DISTRICT COURT
FOR THE NORTHERN DISTRICT OF TEXAS
DALLAS DIVISION

HALLIBURTON ENERGY SERVICES, INC.,

Plaintiff,

v.

WEATHERFORD INTERNATIONAL, INC. and BJ SERVICES COMPANY,

Defendants.

CIVIL ACTION NO. 02-CV-1347-P

HALLIBURTON'S MOTION FOR A
TEMPORARY RESTRAINING ORDER, and BRIEF

Plaintiff Halliburton Energy Services, Inc. ("Halliburton") moves pursuant to 35 U.S.C. § 283 and Fed.R.Civ.P. 65 for a Temporary Restraining Order restraining Defendants Weatherford International, Inc. ("Weatherford") and BJ Services Company, Inc. ("BJ") (collectively, "Defendants") from further infringement of Halliburton's patent rights. Halliburton also moves for a hearing on this Motion. This Motion is supported by Halliburton's Brief in Support of Its Motion for a Preliminary Injunction and attached Appendix filed concurrently herewith.

A temporary restraining order is designed to preserve the status quo until there is an opportunity to hold a hearing on the application for a preliminary injunction. 11A Wright, Miller & Kane, *Federal Practice and Procedure* § 2951, at 253-55 (2d ed. 1995). When the opposing party actually receives notice of the application for a restraining order (as in the present case), the procedure that is followed does not differ functionally from that on an application for a preliminary injunction and the proceeding is not subject to any special requirements. *Id; see also CVI/Beta Ventures, Inc. v. Custom Optical Frames, Inc.*, 859 F.Supp. 945, 948 (D.Md. 1994).

The factors considered by the court in assessing whether to grant a request for a temporary restraining order are similar to the factors examined by the court in determining the merits of a motion for a preliminary injuction. 13 *Moore's Federal Practice* § 65.35, at 65-82 to 65-83 (3d ed. 2002).

Defendants have been given actual notice of Halliburton's Original Complaint and Halliburton's Motions for a Temporary Restraining Order and Preliminary Injunction by service of a true and correct copy thereof on Weatherford by and through its attorney Scott Brown, and on BJ by and through its attorney Margaret B. Kirick, by hand delivery on 21 June, 2002.

WHEREFORE, Halliburton respectfully requests that its Motions for a Temporary Restraining Order and Preliminary Injunction be granted.

Respectfully submitted,

John F. Booth, Texas Bar No. 00265000
Todd E. Albanesi, Texas Bar No. 00969162
David L. Joers, Texas Bar No. 10669800
Peter Schroeder; Texas Bar No. 00794606
Renée Skinner, Texas Bar No. 00791673

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Dallas, Texas 75201-4744
(214) 220-0444; Fax (214) 220-0445

Attorneys for
Halliburton Energy Services, Inc.

CERTIFICATE OF CONFERENCE

Plaintiff has conferred with Defendants' counsel Scott Brown, Weatherford International, Inc., 515 Post Oak Blvd., Suite 600, Houston, TX 77027, (713) 693-4176, and Margaret A. Kirick, BJ Services Company, 5500 Northwest Central Drive, Houston, TX 77092, (713) 895-5657 regarding this Motion, and Defendants' counsel oppose said Motion.

DATED: June 27, 2002

John F. Booth

CERTIFICATE OF SERVICE

I hereby certify that on this 27 day of June, 2002, a true and correct copy of the within document was caused to be served on the attorneys of record at the following addresses as indicated:

BY HAND DELIVERY

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Attorneys for Defendant
BJ Services Company

John F. Booth

IN THE UNITED STATES DISTRICT COURT
FOR THE NORTHERN DISTRICT OF TEXAS
DALLAS DIVISION

HALLIBURTON ENERGY SERVICES, INC., Plaintiff, v. WEATHERFORD INTERNATIONAL, INC. and BJ SERVICES COMPANY, Defendants.	CIVIL ACTION NO.___________

HALLIBURTON'S MOTION FOR A
PRELIMINARY INJUNCTION

Plaintiff Halliburton Energy Services, Inc. ("Halliburton") moves pursuant to 35 U.S.C. § 283 and Fed.R.Civ.P. 65 for a preliminary injunction restraining Defendants Weatherford International, Inc. ("Weatherford") and BJ Services Company, Inc. ("BJ") from further infringement of Halliburton's patent rights. Halliburton also moves for a hearing on this Motion, and for a temporary restraining order until there is an opportunity to hold a hearing on the application for a preliminary injunction.

Halliburton's Motion for a Preliminary Injunction (and Motion for a Temporary Restraining Order) is supported by a Brief in Support, the Declarations of Harold E. McGowen, III and Wesley Jay Burris, II and other exhibits (attached as an Appendix to the Brief), and Proposed Orders, all filed concurrently herewith.

Defendants have been given actual notice of Halliburton's Original Complaint and Motions for a Temporary Restraining Order and Preliminary Injunction by service of true and correct copies thereof on Defendant Weatherford by and through its attorney Scott Brown, and

on Defendant BJ by and through its attorney Margaret B. Kirick, by hand delivery on

__________, 2002.

Respectfully submitted,

____

John F. Booth, Texas Bar No. 00265000
Todd E. Albanesi, Texas Bar No. 00969162
David L. Joers, Texas Bar No. 10669800
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DATED: June 27, 2002

John F. Booth

CERTIFICATE OF SERVICE

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BY HAND DELIVERY Weatherford International, Inc	Scott Brown Patent Counsel Weatherford International, Inc. 515 Post Oak Blvd., Suite 600 Houston, TX 77027 (o) 713-693-4176 (f) 713-693-4480 Attorney for Defendant Weatherford International, Inc.
BY HAND DELIVERY BJ Services Company	Margaret A. Kirick Chief Patent Counsel BJ Services Company 5500 Northwest Central Drive Houston, TX 77092 (o) 713-895-5657 (f) 713-895-5657 Attorneys for Defendant BJ Services Company

John F. Booth

IN THE UNITED STATES DISTRICT COURT
FOR THE NORTHERN DISTRICT OF TEXAS
DALLAS DIVISION

HALLIBURTON ENERGY SERVICES, INC., Plaintiff, v. WEATHERFORD INTERNATIONAL, INC. and BJ SERVICES COMPANY, Defendants.	CIVIL ACTION NO. 02-CV-1347-P

HALLIBURTON'S BRIEF IN SUPPORT OF ITS
MOTION FOR PRELIMINARY INJUNCTION

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ATTORNEYS FOR PLAINTIFF, HALLIBURTON ENERGY SERVICES, INC.

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IN THE UNITED STATES DISTRICT COURT
FOR THE NORTHERN DISTRICT OF TEXAS
DALLAS DIVISION

HALLIBURTON ENERGY SERVICES, INC., Plaintiff, v. WEATHERFORD INTERNATIONAL, INC. and BJ SERVICES COMPANY, Defendants.	CIVIL ACTION NO.____________

HALLIBURTON'S BRIEF IN SUPPORT OF ITS
MOTION FOR A PRELIMINARY INJUNCTION

I. INTRODUCTION

This is a patent infringement case. In its Complaint, Plaintiff Halliburton alleges that Defendants Weatherford and BJ are infringing two of Halliburton's patents.[1] For simplicity, however, this Motion addresses only a few claims of two of the patents, U.S. Patent No. 5,271,468 (the '468 Patent) and No. 5,224,540 (the '540 Patent).[2] The '468 and '540 Patents are attached in the Appendix at **A1-18** and **A19-36**. [Matters contained in the Appendix are referenced as "A," followed by the page number.]

Halliburton is a supplier of services and equipment to customers [well operators and

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[1] U.S. Patent No. 5,271,468 (the '468 patent) issued December 21, 1993 for "Downhole Tool Apparatus with Non-Metallic Components and Methods of Drilling Thereof"; and U.S. Patent No. 5,224,540 (the '540 patent) issued July 6, 1993 for "Downhole Tool Apparatus with Non-Metallic Components and Methods of Drilling Thereof. (collectively, the "Patents-in-Suit").

These patents were issued to Halliburton Company, which in 1996 changed its name to Halliburton Energy Services, Inc. (Plaintiff in this action). See "Certificate of Name Change", **A37-55**.

owners] in the oil industry. Halliburton sells a wide range of well tools and well services utilizing these tools for its customers. Plaintiff's Motion concerns irreparable harm to Halliburton's market for its FAS DRILL® well tools and related well services caused by Defendants.

The '468 and '540 Patents relate to oil well tools that are installed in wells and later drilled out after serving their function. These types of tools are used to plug and seal off the well at a downhole location to isolate one portion of the well from another. These tools are capable of being locked in place in the well bore and are sturdy enough to withstand displacement even when exposed to well pressures of thousands of pounds per square inch and high temperatures. After use, it is necessary to drill these tools out to re-open the well bore. Conventionally, these tools were made of cast iron. **A127, col. 1, lines 54-57.**

The same rugged structural features that permit the tool to withstand high pressures and temperatures present problems when the tool is to be drilled from the well bore. Halliburton's patents are directed to tool designs that solve the decades-old problem of how to reliably, quickly and inexpensively drill out these types of well tools. The inventive tools have certain parts designed to function in the well environment yet are made of easily drillable, non-metallic material. **A9, col. 2, line 60-A10,col.4, line 47.**

In 1994, Halliburton introduced the FAS DRILL® tool line which incorporates Halliburton's patented technology. Since then, Halliburton has sold tens of millions of dollars of the FAS DRILL® tools and related services. **A59, ¶14.** The commercial success of the FAS DRILL® tool's patented non-metallic design was due in part to the drillout disadvantages the cast

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[2] Although not waiving its other claims, Halliburton relies on claims 1 and 30 of the '468 patent and claim 3 of the '540 patent for purposes of preliminary relief; Halliburton's Complaint alleges that both Defendants infringe at least claims 1, 2, 30-32, and 73 of the '468 Patent and claims 1-5 of the '540 Patent.

iron drillable tools offered by Halliburton's competitors [such as Defendants]. **A60-61, ¶¶16-17.**

Recently, both Defendants began marketing and selling downhole tools that infringe Halliburton's patents. Weatherford began marketing and selling a line of tools under the name "FracGuard." **A60-61, ¶17.** BJ began marketing and selling a line of tools under the name "Python." **A61, ¶20.**

Weatherford's and BJ's marketing and selling of their "FracGuard" and "Python" tools is causing Halliburton to suffer millions of dollars of lost sales within the United States of its FAS DRILL® tools and other related products and services. **A62-66, ¶¶24-38.** Weatherford and BJ are targeting Halliburton's customers by undercutting Halliburton's prices for its patented FAS DRILL® tools. **A62-63, ¶25.** Halliburton is being forced to meet Defendants' downward trend pricing by lowering its pricing for its FAS DRILL® products and related well services. **A63, ¶27.** If Halliburton's price for its patented product and services is lowered, further future price increases to return to current levels will be virtually impossible.. **A63, ¶28.** Defendants have been and are taking portions of Halliburton's market for its patented well tools. **A62, ¶24.**

Defendants' infringement is continuing at a critical time in the well servicing market. After a period of continued growth, the "oil rig count" has declined resulting in a related reduction in the market for well services. Halliburton's market share losses in its FAS DRILL® tool market to Defendants is contributing to Halliburton's plans to institute layoffs of well-servicing employees. Losing good Halliburton people causes present and future economic damages to Halliburton which defy easy calculation. When the market returns to a growth phase, experienced employees like these will be difficult and costly to replace and train. **A65, ¶37.** In the absence of experienced applicants, Halliburton will be forced to expend future dollars on training replacements for those qualified individuals.

Left unchecked, Defendants' infringement will continue to drive prices lower and cause further damage to Halliburton's market price for its patented FAS DRILL® products and services. **A66, ¶38.**

Halliburton has notified both Defendants Weatherford and BJ of the existence of the '468 and '540 Patents and of its concerns that their tools were infringing Halliburton's patent rights. During Halliburton's investigation of this matter, Halliburton requested and Defendants refused to provide sample products for examination by Plaintiff's technical experts Halliburton has been unable to obtain samples from the market.[3] Defendants tightly controlled access to their tools in the market. On May 7, 2002, however, Plaintiff's expert attended an industry trade show in Houston and was able to ask questions of Defendants' sales representatives and examine display samples of Defendants' tools. See, **A98-104** and attachments thereto, **A112, A114.**

Halliburton had hoped that the present dispute could be resolved without costly, extensive litigation, and without substantial intervention by the Court. Unfortunately, Weatherford and BJ refuse to stop selling the infringing "FracGuard" and "Python" drillable tools. Accordingly, Halliburton seeks injunctions against Weatherford's and BJ's sale and use of the "FracGuard" and "Python" tools to prevent further infringement of its patents.

II. FACTUAL BACKGROUND

A. WELLS AND WELL-COMPLETION SERVICES

Well tools are used downhole in oil wells in a variety of situations, a brief description of "fracing" procedures, a common use for the patented FAS DRILL® tools, will assist the Court's understanding of the patented tools and how as well as the methods for their use in well

[3] In January of 2002, Weatherford provided a tool for examination at its Houston offices. This examination was conditioned upon Halliburton's agreement not to photograph the tool and not to allow it to be examined by technical experts. Only Halliburton counsel were allowed to view the tool.

processing services and the problems associated with their removal. In addition to the descriptions contained in the attached patents, a brief discussion of well completion is contained in copies from F. Baker, *A Primer of OilWell Drilling*, pp. 151-156 (6th ed. 2001). **A115A-120.**

Oil and gas wells are drilled into the earth using large drilling rigs capable of lifting and rotating long, heavy "strings" of drill pipe with a drill bit at the end. These wells can be very deep, penetrating thousands of feet into the earth. **A137.** A well bore that is thousands of feet deep often passes through several vertically separated oil-and-gas bearing formations, which are referred to as "production zones" or simply "zones." **A137.**

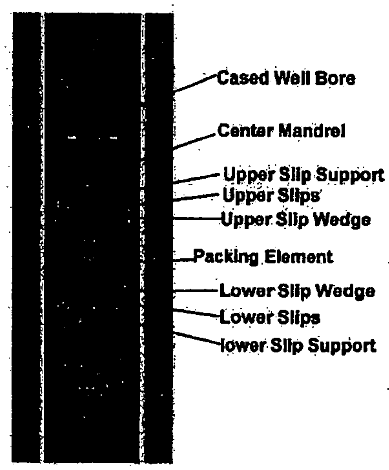
After the well is drilled, a string of relatively large-diameter tubing called "casing" is lowered into the well bore by the drilling rig and then cemented in place. **A115.** Once the casing is cemented in place, the well must be "completed" to ready it for production from the oil-and-gas-bearing formations. Holes must be made in the casing where it intersects the production zones so that the oil and gas can flow into the well. This procedure, called "perforating," is accomplished by firing small explosive charges from inside the well to form openings in the casing wall and into the surrounding production zone or by otherwise cutting holes in the casing wall. **A116-117.**

Sometimes oil and gas flow to the well from the production zone is poor. To enhance the hydrocarbon flow, operators commonly use a procedure called "fracing" (pronounced frack'ing). **A120.** This procedure involves pumping fluids at high pressures, often in the range of 5,000 – 10,000 pounds per square inch ("psi"), down the well bore, out through the perforations in the casing, and into the surrounding producing zone. Pumping this high pressure fluid into the zone causes it to crack or "fracture." The fracture provides a flow path for increased fluid flow from the production zone to the well bore. **A120.**

Often maximizing production requires that the well operator frac more than one production zone of a well bore. Performing multiple fracing procedures on different portions of the same well is called "staged fracturing," which is performed by sequential fracing from the lowest zone upward. **A137-144**. After fracing a zone, the well bore is plugged just below the next higher zone to be fraced so that the high-pressure fluid pumped into the well bore does not enter the perforations in the previously fraced zone below. This procedure can be successively staged for fracing additional zones.

B. DOWNHOLE TOOLS FOR PLUGGING THE WELL BORE

In general, downhole tools used to plug and seal a well bore are called "bridge plugs." These tools include a "center mandrel" [the main structural body on which the tool is built], a packing element [a generally doughnut-shaped, rubber element positioned around the center mandrel] and anchoring assemblies to hold the tool in place ["slip" assemblies for grippingly engaging the well bore when in a set position].



Well Tool Illustration

C. THE PROBLEM: HOW TO GET THE PLUG OUT

To be successful, a bridge plug must have a rugged structure to withstand high fracing pressures, often in range of 5,000 psi to 10,000 psi, and high temperatures, often in the range of 250°F to 425°F. **A11, col. 6, lines 27-34**. That means the tool must be a very durable and must be able to be tightly wedged into the well bore. However after the tool has served its purpose, well operators usually want to remove the tool to re-open the well bore. The same structural requirements necessary for a tool to withstand high pressures and temperatures present problems in efficient removal of a tool from the well bore.

Early attempts to solve the problem involved the use of a "retrievable" tool, with a latch-and-release mechanism; these tools however are unreliable, complex, and expensive to use. **A127, col. 1, lines 28-30.** For example, the release mechanism often becomes fouled with debris and mud preventing release.

A partial solution was to use a "drillable" tool made from easier-to-drill metallic materials such as cast iron [**A127, col. 1, lines 54-55**] rather than steel. This method, involved drilling the tool would be drilled into small metallic bits and chips that could be circulated (flushed) out of the well bore. This solution also proved difficult in practice because the drill out process required heavy drilling equipment and long drilling times which can damage well equipment and open production zones. All of these factors add up to a costly removal operation.

Despite the expense of keeping drilling rigs at a well during the completion process [or moving off and returning to the well], drillable cast iron tools were still used in well service operations because they were less expensive and more reliable than retrievable tools. **A127, col. 1, lines 28-30.** Defendants Weatherford and BJ have offered and continue to offer these cast iron drillable well tools to the well servicing market. **A60, ¶16; A61, ¶19.**

While the need for truly drillable tools continued [**A127, col. 2, lines 23-27**] other solutions were proposed. In the mid 1980's, two inventors at The Western Company in Fort Worth worked to improve the drillability of well service tools. They proposed designing well tools with some components made from nonmetallic materials. Their efforts were reported in 1987 in U.S. Patent No. 4,708,202 (the '202 Patent). **A121-136.** In tool designs according to the '202 Patent, metallic materials were proposed for the high stressed critical tool components [cast iron "mandrel" and "slips"] and nonmetallic composite materials were proposed for the non-critical tool components. The '202 Patent does not report the drill out data for these tools. The

tools described in the '202 Patent are not known to be available in the market today. However, even if such tools existed, their drill out likely would require extensive drilling times with heavy expensive drilling equipment because of the tools reliance metallic mandrels.

D. HALLIBURTON'S PATENTED INVENTIONS

In the late 1980s and into the 1990s, Halliburton conducted research in the drillable tool field. As a result, Halliburton's engineers developed a rugged tool design that could withstand the rigors of downhole well conditions, yet featured a center mandrel of non-metallic composite material to permit easy drill out.

The '468 and '540 Patents describe a variety of packer and bridge plug tool configurations. Since Defendants' infringing tools are bridge plugs, the discussion herein will focus on the bridge plug embodiments shown in Figures 7 and 8 of the '468 Patent and the '540 Patent. **A14, col. 12, line 60–col. 13, line 17.**

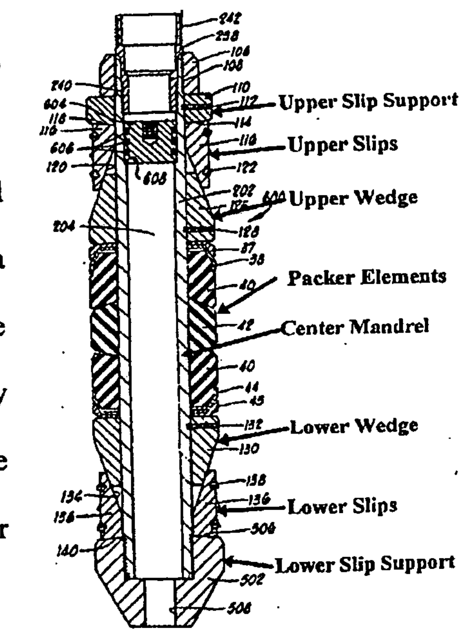


FIG. 8

5,271,468

The bridge plug [600] in Fig. 8 is assembled on a central mandrel [202] with a central passageway [204] blocked off by a plug [604]. Donut shaped rubber packing elements [40 & 42] are positioned on the mandrel [202] between an upper slip assembly [upper slip support (110), upper slip (116) and upper wedge (126)] and a lower slip assembly [lower slip wedge (130), lower slip (136) and lower slip support (502)].

As the '468 Patent explains, the mandrel and slips designs are critical to the tool's operation because of loading during use:

> Most of the components of the slip means are subjected to substantially compressive loading when in a sealed operating position in the well bore, although some tensile loading may also be experienced. The center mandrel typically has tensile loading applied thereto when setting the packer and when the packer is in its operating position. **A10, col. 3, lines 49-55.**

The '468 Patent is also directed to the methods (or processes) of using non-metallic tools and contains claims to methods of their use which are relevant to Defendants' activities:

> One new method of the invention is a well bore process comprising the steps of positioning a downhole tool into engagement with the well bore; prior to the step of positioning, constructing the tool such that a component thereof is made of a non-metallic material; and then drilling the tool out of the well bore. **A10, col. 3, lines 56-63.**

The "setting" and "locking" procedures involve axially compressing the components mounted on the mandrel until the rubber packing elements expand radially and seal with the well bore. Simultaneously the upper and lower slip assemblies are locked in gripping engagement with the well bore. **A15, col. 13, line 18-col. 14, line 20.** Once set, the tool is self-supporting in the well bore as shown in Fig. 1. These tools are not only set in the well, they are also locked in place so that the only procedure for removal is drilling out. Fig. 1 of the '468 Patent (and the '540 Patent) illustrates a drillable bridge plug well tool [10] set in a cased well bore [12] with a drill [14] positioned above the tool [10] ready to drill it out of the well. **A11, col. 5, lines 4-16.** One advantage of the inventions of the '468 and '540 Patents is that drillout requires no expensive heavy drilling rig.

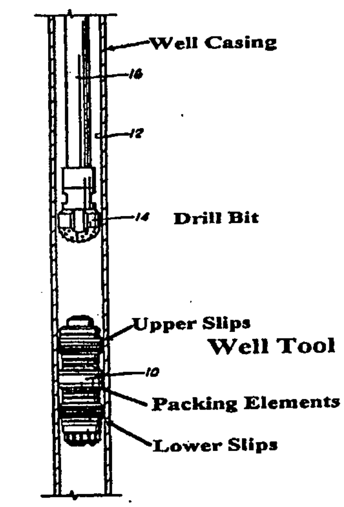


FIG. 1

5,271,468

E. Halliburton's Patented FAS DRILL® Tools Revolutionized The Drillable Tool Market

In 1994, Halliburton introduced the first of its FAS DRILL® tools. **A58, ¶7.** See also, FAS DRILL® Product Sheets, **A67-72;** and [SAVAGE], *Taking New Materials Downhole-The Composite Bridge* Plug, PNEC 662,935 (1994), **A169-172.** Historically, well operators are reluctant, however, to try unproven tools in their wells because of the enormous economic consequences of failure. Non-metallic structural products faced even greater skepticism.

Based upon market research and its knowledge of industry attitudes, Halliburton designed and implemented a focused program to market the new tool, Halliburton conducted extensive tests to demonstrate the reliability of this revolutionary new line of tools. Halliburton started a market development program to educate the industry. Additionally, Halliburton submitted and continues to submit technical papers describing its tests results for peer review and publication by the Society of Petroleum Engineers (SPE). i GUOYNES, *New Composite Fracturing Plug Improves Efficiency in Coalbed Methane Completions*, SPE 40052 (1998) **A173-183,** LONG, *Improved Completion Method for Mesaverde-Meeteetse Wells in the Wind River Basin*, SPE 60312, (1999) **A137-144** and EBERHARD, *The Effect of Stimulation Methodologies on Production in the Jonah Field*, SPE 71048, (2001), **A145-153.** Halliburton created software animations of the tools' operation and conducted seminars for potential customers. See Computer Disk, Halliburton TOOL SIMULATOR LITE. **A154.**

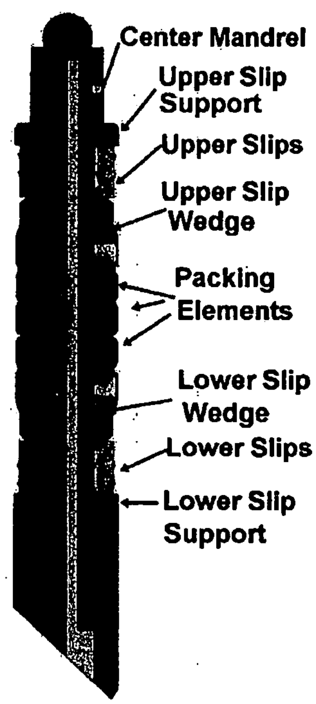
Halliburton's FAS DRILL® tool line does not require expensive heavy drilling rig to drill them out of the well. See, SPE 60312 Article, "rigless completion" at **A140.** This innovation revolutionized the industry because using the FAS DRILL® tools, allowed well operators to dismantle and permanently remove the drilling rigs (with its high daily cost) off the well once the casing was set. Eliminating the need for an expensive drilling rig saved well operators enormous

sums of money. The well operators could use a less expensive coil tubing drilling unit when needed to quickly drill out the FAS DRILL® tools while in an underbalanced well condition. **A170-171.** A coiled tubing unit is illustrated in Defendant BJ's sales literature. **A93.**

The FAS DRILL® only required 15 to 30 minutes [**A139**] for removal significantly less than the 4 to 6 hours for a cast iron plug. **A127, col. 1, line 61-64.** This created an enormous savings in removal costs in multi stage-frac procedures.

Because well operators tended to use one service supplier for all completion steps, Halliburton's ability to deliver enormous savings and increased production with its FAS DRILL® tools made it the supplier of choice. **A64, ¶34.** These enormous savings and increased production also made operators willing to pay higher prices to Halliburton for its tools, when increased customer demand required Halliburton to sell the FAS DRILL® products separately from its services, it did so at premium prices. **A59, ¶13.**

FAS DRILL® Frac Plug



F. HALLIBURTON'S PATENTED FAS DRILL® TOOLS OPENED NEW MARKETS FOR DRILLABLE TOOLS

This new technology gave petroleum engineers greater flexibility in designing new treatment procedures for wells. For example, a problem presented by multi-stage fracing was that plugs set in a well bore below the next zone to be treated would prevent the flow back of fluid from the treated zones below that plug.

This problem was partially addressed simply by the ability of the FAS DRILL® plug to be quickly drilled out of the well bore after the fracing procedure. This solution still required changing from a pumping operation used in fracing to a drilling operation to drill out the lower plug, even if the drilling operation could be quickly accomplished with lightweight drilling

equipment.

In 1998, Halliburton introduced a FAS DRILL® Frac Plug. A frac plug has a valve in the central passageway with a check valve mechanism, such as a ball and seat, that allows fluid to flow upward but blocks flow down through the plug. **A58, ¶9.** The tool plugs the well from above allowing the high-pressure fluid being pumped down the wellbore causes the ball to be pushed down on the seat and block the central passageway to the lower zone. In this method, the high high-pressure fluid pumped into the well bore does not leak out into the perforations in the previously fraced zone or lower zones. When the pumping pressure is released, fluid can flow upward from the lower zones, lifting the ball off the seat, and allowing production of the lower zone without immediate drill out.

After performing the multi-stage frac procedure, the operator can use a light-weight drilling rig to quickly and serially drill out all frac plugs at one time. Thus, the ease of drillability of the patented tools opened up new uses and markets for the tools. In addition to substantially reducing drill out time and costs, FAS DRILL® frac plugs allowed well completion procedures that caused less damage to the producing zone resulting in increased production. [SPE 60312 Article, **A140** and SPE 71048 Article, **A148**].

G. DEFENDANTS' ACCUSED "FRACGUARD" AND "PYTHON" PLUGS

Defendants Weatherford and BJ are suppliers of a wide range of downhole tools, including drillable packers and bridge plugs. **A60, ¶16; A61, ¶19.** Before the summer of 2001, Defendants offered drillable well tools with cast iron components. However, these tools did not offer the ease of drilling ease and savings of Halliburton's patented FAS DRILL® tools. **A60, ¶16; A61, ¶19.**

Sometime in late summer of 2001, Weatherford began marketing its drillable well tool

products with non-metallic components known as the "FracGuard Composite Bridge Plug" and "FracGuard Composite Frac Plug." **A60, ¶17.** At about the same time, BJ began marketing its drillable well tool product known as the "Python Composite Bridge Plug." **A61, ¶20.**

Defendants' tools incorporate patented aspects of the Halliburton FAS DRILL® tools and infringe the patents-in-suit. Like the FAS DRILL®, Defendants' tools are particularly designed to be set and locked in position in wells and to be easily drilled out. **A61-62, ¶¶18, 21-23; A99 ¶¶ 5-6; A100, ¶11(a); A103, ¶15(a).**[4] Defendants' representatives have admitted that their tools incorporate center mandrels [bodies] made of a non-metallic composite material. **A101 ¶11b, A103 ¶15b.** Defendants' tools have upper and lower slip assemblies made at least partially of a non-metallic composite material. **A101-102, ¶¶11(d-f); A103-104 ¶¶15(d-f).** Weatherford has offered for sale, sold and continues to sell its "FracGuard" drillable tools and supervises their installation in wells. **A62, ¶24.** BJ offers for sale its "Python" tools installs them in wells, drills them out and performs related well services. **A62, ¶24.**

III. ARGUMENT

A. LEGAL STANDARDS FOR GRANTING PRELIMINARY INJUNCTIONS

Congress has authorized district courts in patent cases to grant injunctions "in accordance with the principles of equity to prevent the violation of any right secured by patent, on such terms as the court deems reasonable." 35 U.S.C. § 283. That provision authorizes courts in infringement actions to grant preliminary injunctions pending trial.

A preliminary injunction or temporary restraining order requires the assessment of four

[4] See also, Weatherford's published FracGuard materials [Drill Out: "Drills out quickly with a conventional tri-cone or junk mill bits, saving time" **A73-74 (W5-6), 110-111(W1-2),** "composite body and component construction allow for rapid drill up." **A110-111(W1-2);** Setting: "can be run using conventional setting equipment" **A74 (W6), 110-111(W1-2)];** Sealing: "Holds full differential pressures" **A110-11(W1-2).** Similarly BJ's published Python materials state: [Drill Out: "constructed of high tech composite materials, which are easily drillable with coiled

factors: the likelihood of movant's success on the merits, the irreparability of harm to the movant without an injunction, the balance of hardships between the parties, and the demands of the public interest. *See Mentor Graphics Corp. v Quickturn Design Systems Inc.*, 150 F.3d 1374, 1377, 47 U.S.P.Q.2d 1683, 1685 (Fed. Cir. 1998); see also, 35 U.S.C. § 283. None of these four factors, taken alone, is dispositive. Instead, the Court must weigh and measure each factor against the others and against the form and magnitude of the relief requested. *Hybritech Inc. v. Abbott Lab* 849 F.2d 1446, 1451 (Fed. Cir. 1988).

While the patentee-movant initially bears the burden of proof with regard to each of the four factors, the burden is no more stringent in patent cases than it is in other types of cases, *Reebok Int'l Ltd. V. J. Baker, Inc.*, 32 F.3d 1552, 1555-56 (Fed. Cir. 1994), and the patentee movant may rely upon statutory or other presumptions, such as the statutory presumption that a patent is valid, as may be inherent in the nature of the case. *Id.*; 35 U.S.C. § 282.

Injunctive relief is critical to the preservation of intellectual property rights. *Smith Int'l Inc. v. Hughes Tool Co.*, 718 F.2d 1573, 1577-78 (Fed. Cir.), *cert. denied,* 464 U.S. 996 (1983). "Where a case for a temporary injunction is clearly made out, it is not open to the trial court to deny the remedy." *Id.* At1579. Federal Circuit will reverse a grant of Preliminary Injunction only if the district court has "abused its discretion, committed an error of law, or seriously misjudged the evidence." *Hybritech,* 849 F.2d at 1449.

In the present case, each of these factors strongly favors granting a preliminary injunction.

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tubing unit." **A113 (BJ1), A83 (BJ11)**; Setting: "The tool is run on the Baker #10 Wireline Pressure Setting Assembly." **A113(BJ1), A90(BJ18)**, Sealing: "High Pressure Performance" **A83,(BJ11)**.

B. Halliburton Has Demonstrated A Likelihood Of Success On The Merits

1. The Law of Patent Infringement

A patent grants to its owner the right to exclude others from importing, making, using, selling, and offering to sell patented inventions or inducing or contributing to the inventions use by others for the term of the patent. 35 U.S.C. § 271.

To establish literal infringement, a plaintiff must demonstrate that every limitation in the claim is literally met by the accused device or process. *Enercon GmbH v. U.S. Int'l Trade Comm'n*, 151 F.3d 1376, 1384, 47 U.S.P.Q.2d 1725, 1731 (Fed. Cir. 1998). A party may be liable for direct infringement of a process claim even where the various steps included in the patent are performed by different persons. *See, e.g., E.I. DuPont De Nemours & Co. v. Monsanto Co.*, 903 F.Supp. 680, 735 (D.Del. 1995), *aff'd without op.*, 92 F.3d 1208 (Fed. Cir. 1996) (third party purchased a product on which Monsanto had performed the first step of a three-step patented process for producing stain resistant carpet fibers, and then performed the last two steps of the process itself). Infringement can be proven by circumstantial evidence. *Alco Standard Corp. v. TVA*, 808 F.2d 1490, 1 U.S.P.Q.2d 1337, 1346 (Fed. Cir. 1986).

Determination of the issue of infringement entails a two-step analysis – (1) construction of the claims, as a matter of law; and (2) application of those claims to the accused device which is a question of fact. *Voice Techs. Group, Inc. v. VMC Sys., Inc.*, 164 F.3d 605, 612, 49 U.S.P.Q.2d 1333, 1337 (Fed. Cir. 1999).

In addition: "Whoever actively induces infringement of a patent shall be liable as an infringer." 35 U.S.C. § 271(b). Inducement embraces a wide variety of sales-related activities, including advertising, solicitation, and product instruction. *See, e.g., Chiuminatta Concrete Concepts, Inc. v. Cardinal Industries, Inc.*, 145 F.3d 1303, 46 U.S.P.Q.2d 1752 (Fed. Cir. 1998)

(By advertising and selling a rotary saw for cutting concrete, an accused infringer actively induced infringement of a method patent claim that required cutting concrete at a specified stage of hardening; the advertisements encouraged use during the claimed hardness range); see also, *Mickowski v. Visi-Trak Corp.*, 36 F.Supp.2d 171, 180 (S.D. N.Y. 1999) (accused infringer's sales literature and product manual encouraged purchasers of its product to use the patented method).

Also, selling tools especially designed for use in infringing Halliburton's patented method can be contributory infringement. Title 35 U.S.C. §271.

2. Infringement by Defendants' "FracGuard" and "Python" Tools And Methods Is Clear

Defendant BJ directly infringes method Claim 1 of the '468 Patent by setting in the well and drilling out the "Python" plugs with "non-metallic mandrels." Defendant Weatherford "induces" and contributes to infringement by its customers of Claim 1 of the '468 patent by selling the "FracGuard" tools to its customers who set them in wells and drill them out. Both Defendants Weatherford and BJ directly infringe apparatus Claim 30 of the '468 Patent and apparatus Claim 3 of the '540 Patent by making, using, offering for sale, and selling their "FracGuard" and "Python" tools respectively.

In general, method Claim 1 of the '468 Patent [A16] is directed to a well bore process, including the steps of constructing a downhole tool which has a non-metallic mandrel, positioning the downhole tool into locking, sealing engagement with said well bore, and then drilling the tool out of the well bore. Both Defendants' sales literature and instructions clearly contemplate that the tools will be set in the well and then drilled out. BJ's literature reports that BJ has conducted drill out tests for its Python tool, a direct infringement of Claim 1. Weatherford's literature states that the "FracGuard" tool "[d]rills out quickly" and BJ's literature states that the "Python" tool is "easily drillable." Defendants have also induced others to

infringe claim 1 of the '468 patent. When Weatherford or BJ sells a tool to a customer, they induce the customer to set the tool in a well bore and then drill it out of the well bore. Because Weatherford and BJ urge their customers to use the "FracGuard" and "Python" tools in a manner which meets each and every limitation of claim 1 of the '468 patent, Weatherford and BJ are guilty of inducing infringement in violation of 35 U.S.C. § 271(b). *See, e.g., Rexnord Inc. v. Laitram Corp.*, 6 U.S.P.Q.2d 1817, 1842 (E.D. Wisc. 1988) ("Liability under 35 U.S.C. 271(b) can be established where a party takes active steps to induce infringement through advertising or by providing instructions.")

Infringement under Section 271(c) is known as "contributory infringement." To establish liability for contributory infringement, Halliburton must show: (1) the "FracGuard" and "Python" tools have an "apparatus for use in practicing a patented process," (2) Weatherford and BJ know that the "FracGuard" and "Python" tools are "made or especially adapted for use in an infringement," and (3) the "FracGuard" and "Python" tools are "not a staple article of commerce suitable for substantial non-infringing use." 35 U.S.C. § 271(c). Here the primary advertised use of the "FracGuard" and "Python" is to infringe Claim 1. Thus, both products qualify as an "apparatus for use in practicing a patented process." Moreover, Weatherford and BJ clearly know that the "FracGuard" and "Python" are "made or especially adapted for use in an infringement." Weatherford and BJ manufacture the "FracGuard" and "Python" and advertise their infringing use. Further, the "FracGuard" and "Python" tools have no "substantial non-infringing use." Thus, Weatherford's and BJ's sale of their "FracGuard" and "Python" tools qualify as contributory infringement under Section 271 (c).

Claim 30 of the '468 Patent is directed to a downhole tool having a center mandrel made of a non-metallic material, and "slip means disposed on said mandrel for grippingly engaging

said well bore when in a set position." Since the FracGuard and Python products each contain these elements, Defendants' making, offering for sale, sale, and use of these tools constitute a direct infringement of Claim 30.

Claim 3 of the '540 Patent is also directed to a downhole tool including a center mandrel, "a slip means disposed on said mandrel for grippingly engaging said well bore when in a set position," and further specifies that the "slip means is an upper slip means disposed above said packing means and further comprising a lower slip means disposed below said packing means." Claim 3 is a "dependent" claim which refers back to Claim 2, which in turn refers back to Claim 1 of the '540 Patent. Thus, to understand Claim 3, all of Claims 1, 2, and 3 of the '540 Patent must be read together. See, 35 U.S.C. 112, ¶ 4. Defendants' offering for sale, sale and use of the FracGuard and Python tools is a direct infringement of Claim 3.

A detailed comparison can be found in the claim charts which clearly demonstrate that Weatherford's and BJ's composite tools and other activities infringe Claims 1 and 30 of the '468 Patent and Claim 3 of the '540 Patent. **A155-163.**

These patent claims are straight forward and the evidence of infringement is overwhelming and more than sufficient to show a likelihood of success on the merits at trial.

3. Halliburton is Highly Likely to Succeed on Validity

Under 35 U.S.C. § 282, Halliburton's patents are presumed valid, and Defendants bear the burden of proving invalidity by clear and convincing evidence. *Innovative Scuba Concepts, Inc. v. Feder. Indus., Inc,* 26 F.3d 1112, 1115, 31 U.S.P.Q.2d 1132, 1134 (Fed. Cir. 1994). Section 282 provides that each claim of a patent with multiple claims is presumed valid independent of the validity or invalidity of any other claim.

Halliburton is entitled to rely on the presumption of validity when moving for a

preliminary injunction. *Canon Computer Systems, Inc. v. Nu-Kote Int'l, Inc.*, 134 F.3d 1085, 1088, 45 U.S.P.Q.2d 1355, 1358 (Fed. Cir. 1998). In ruling on Plaintiff's Motion, the Court must decide whether Halliburton has demonstrated a reasonable likelihood that Defendants will fail to meet their burden at trial, by clear and convincing evidence, that the claims of Halliburton's patents are invalid. *H.H. Robertson Co. v. United Steel Deck, Inc.*, 820 F.2d 384, 387 (Fed. Cir. 1987).

In this case, Defendants will be unable to make a clear and convincing showing of invalidity. Defendants' materials either do not qualify as prior art or can be distinguished from claims 1 and 30 of the '468 Patent and claim 3 of the '540 Patent. The materials discussed below are expected to be relied on by Defendants to assert that one or more claims of the patents-in-suit are invalid.

a. Alleged Prior Use

Defendant Weatherford has previously made a bare allegation that it has a declaration of an "inventor" who is aware of a prior "public use" relevant to the validity of the '468 and '540 Patents. Weatherford has refused Halliburton's requests to produce the declaration or any evidence supporting its allegation. At this point, Weatherford has come forward with no credible evidence to prove this assertion.

b. U.S. Patent No. 4,708,202 (the '202 Patent)

Defendants are expected to assert the '202 Patent issued to the Western Company in 1987, described above (subheading "II C") anticipates and invalidates the patents-in-suit. The Patent and Trademark Office considered the '202 Patent before allowing the '468 and '540 Patents. *See Hewlett-Packard Co. v. Bausch & Lomb, Inc.*, 909 F.2d 1464, 15 U.S.P.Q.2d 1525 (Fed. Cir. 1990) (the burden of showing invalidity is especially difficult when the prior art was

before the PTO). The Patent and Trademark Office found that the '202 Patent fails to disclose or suggest the inventions claimed in the '468 and '540 Patents. Further, Defendants chose not to use the '202 design and instead used Halliburton's inventions. *See Specialty Composites v. Cabot Corp.*, 845 F.2d 981, 6 U.S.P.Q.2d 1601 (Fed. Cir. 1988) (the fact that an accused infringer did not copy any prior art device, but found it necessary to copy the claimed invention, is strong evidence of validity).

c. The 1968 Baker Tension Packer Advertisement

In the June 1968 issue of *World Oil*, Baker Oil Tools, Inc. ran an ad for "corrosion proof" fiberglass tension packers for connection to fiberglass pipe. **A164–166.** The ad is for retrievable tubing mounted tension packers. Defendants have the burden of proving that this ad qualifies as prior art by clear and convincing evidence.

Even if the ad were proven to be appropriate prior art, the tension packers discussed are distinguishable and not relevant to Halliburton's drillable tool inventions. The advertised tools were not designed to be "positioned into locking, sealing engagement with the well bore" as required in method claim 1 of the '468 Patent, nor do the tools have "slip means disposed on said mandrel for grippingly engaging said well bore when in a set position" as required by claim 30 of the '468 Patent and claim 3 of the '540 Patent. Moreover, the tool appears to have been a commercial failure for any purpose, even for the problem of corrosion resistance that it purported to remedy. In particular, there is no evidence that Baker ever advertised or used this tool again after June of 1968.

d. The 1968 Baker Special Products Manual

Defendants have asserted that an unauthenticated two page Special Products Manual for a "Baker Prime Fiberglass Packer" dated April 5, 1968 is also prior art. **A167-168.** Even if

Defendants authenticate the Manual the tension packer referred to in the Manual fails as prior art for the same reasons as the 1968 Baker ad.

e. Objective Evidence From the Marketplace Strongly Supports Validity

The evidence presented with this motion supports the conclusion that invention of the Patents-in-Suit are novel and not obvious. For example, secondary considerations which are "essential components of the obviousness determination" include, among other things, copying, long felt but unsolved need, failure of others, commercial success, unexpected results created by the claimed invention, unexpected properties of the claimed invention, and licenses "showing industry respect for the invention." *In re Rouffet*, 149 F.3d 1350, 1355 (Fed. Cir. 1998). The fact of Defendants' direct copying of FAS DRILL ®, the immediate and substantial commercial success of FAS DRILL ®, and the fact that FAS DRILL ® satisfied the long felt need for a truly drillable well tool all evidence the validity of Halliburton's inventions.

This evidence is "virtually irrefutable" proof of validity. *Panduit Corp. v. Dennison Mfg. Co.*, 774 F2d 1082, 1099 (Fed. Cir. 1985).

C. CONTINUED SALES BY DEFENDANTS WILL CAUSE IRREPARABLE HARM TO HALLIBURTON

1. Halliburton's Irreparable Harm is Preserved

The Federal Circuit has held that a presumption of irreparable harm arises when a patentee makes a clear showing that a patent is valid and that it is infringed. *Polymer Technologies, Inc. v. Bridwell* 103 F.3d 970, 973 (Fed. Cir. 1996). This presumption shifts the ultimate burden of production on the issue of irreparable harm onto the alleged infringer. *Roper Corp. v. Litton Systems, Inc.*, 757 F.2d 1266, 1272 (Fed. Cir. 1985).

Because Halliburton has made a clear showing of infringement and that the patent will

withstand challenges to its validity, Halliburton is entitled to a finding of irreparable injury based solely upon the presumption of irreparable harm, without any evidence of actual irreparable harm. "The very nature of the patent right is the right to exclude others. Once the patentee's patents have been held to be valid and infringed, he should be entitled to the full enjoyment and protection of his patent rights... A court should not be reluctant to use its equity powers once a party has so clearly established his patent rights." *Smith Int'l,* 718 F.2d at 1581. To hold otherwise would be contrary to the public policy underlying the patent laws. *Id.* For "[i]t is well-settled that, because the principal value of a patent is its statutory right to exclude, the nature of the patent grant weighs against holding that monetary damages will always suffice to make the patentee whole." *Hybritech* 849 F.2d at 1456-57; *accord Reebok,* 32 F.3d at 1557.

To prevail on the issue of irreparable harm, Defendants would have to rebut the presumption of irreparable harm with clear evidence. *See Roper*, 757 F2d at 1272. That they cannot do. Defendants' financial ability to compensate Halliburton after trial would not be sufficient to rebut the presumption of irreparable harm. *Polymer Technologies, Inc. v. Bridwell* 103 F.3d at 975 (citing *Roper*).

2. Halliburton's Actual Irreparable Harm

Even apart from the presumption of irreparable harm, Halliburton's loss of market share and business relationships due to Defendants' infringement independently constitutes irreparable harm. *Schawabel Corp. v. Conair Corp.*, 122 F.Supp.2d 71, 83-84 (D. Mass. 2000). Halliburton's "loss of existing market share, price erosion and lost market penetration and expansion opportunities" would result in irreparable injury absent grant of a preliminary injunction. *See Solarex Corp. v. Advanced Photovoltaic Sys.*, 34 U.S.P.Q.2d 1234, 1240 (D. Del. 1995). These market effects can never be fully compensated by money. **A66, ¶38.** "If monetary

relief were the sole relief afforded by the patent statute then injunctions would be unnecessary and infringers could become compulsory licensees for as long as the litigation lasts." *Atlas Powder Co. v. Ireco Chems.*, 773 F.2d 1230, 1233 (Fed. Cir. 1985).

Halliburton's inventions opened up the stated frac market to drillable tools and created an entirely new major market for Halliburton's drillable tools and related services. **A60, ¶15.** *See Colonial Data Techs. Corp. v. Cybiotronics Ltd.*, 41 U.S.P.Q.2d 1763, 1769 (D.Conn. 1996) ("In addition to the potential loss of sales, [the patentee] also risks losing the opportunity to remain a leader and maintain its market share.")

Defendants have been marketing their infringing tools at substantially lower prices than Halliburton was marketing its "FAS Drill" tools prior to Defendants' entry into the market. **A62-63, ¶25.** Halliburton has been forced to increase its offered discounts up to about 50% and more off its list pricing to continue to sell its "FAS Drill" tools. Halliburton's profit margins on its "FAS Drill" product line are being eroded quickly. **A63, ¶27.** As the Federal Circuit has recognized in *Polymer Tech., Inc. v. Bridwell*, 103 F.3d 970, 975-6 (Fed. Cir. 1996):

> Competitors change the marketplace. Years after infringement has begun, it may be impossible to restore a patentee's (or an exclusive licensee's) exclusive position by an award of damages and a permanent injunction. Customers may have established relationships with infringers. The market is rarely the same when a market of multiple sellers is suddenly converted to one with a single seller by legal fiat. Requiring purchasers to pay higher prices after years of paying lower prices to infringers is not a reliable business option.

Halliburton "is likely to lose good will with its customers because of the pricing difference between" Halliburton's and Defendants' products. **A63, ¶¶29.** *See LifeScan Inc. v. Polymer Tech. Int'l Corp.*, 35 U.S.P.Q.2d 1225, 1240 (W.D. Wash. 1995); *accord Alcon Lab., Inc. v. Bausch & Lomb, Inc.*, 52 U.S.P.Q.2d 1927, 1934 (N.D.Tex. 1999) (patent owner would

suffer irreparable price erosion). The adverse impact on Halliburton's market share and pricing structure can never be fully quantified in dollars. **A63, ¶28.**

Due to Weatherford's and BJ's marketing and sales of their "FracGuard" and "Python" tools, Halliburton has also experienced a decline in the sale of non-patented products and well services that relate to the use of a drillable composite bridge plug or frac plug tool. **A59, ¶12; A65, ¶36.** *See 3M Unitek Corp. v. Ormco Co.*, 96 F.Supp.2d 1042, 1051 (C.D.Cal. 2000) (defendants' infringement would hurt plaintiff's market position for both the patented products as well as its other products). Defendants will use their ability to supply the infringing tools to create customer relationships that would have been Halliburton's. **A65, ¶36.** Halliburton's evidence clearly demonstrates the presence of irreparable harm.

D. THE BALANCE OF HARDSHIPS FAVORS HALLIBURTON

In balancing hardships, the magnitude of the threatened injury to the patent owner is weighed, in light of the strength of the showing of likelihood of success on the merits, against the injury to the accused infringer. *H.H. Robertson*, 820 F.2d at 390. Moreover, a preliminary injunction may be granted even where "neither party has a clear advantage" in the balance of hardships. *Hybritech*, 849 F.2d at 1457.

Halliburton, as the patent owner, stands to incur the greater damage here. Halliburton "is subject to continuing price erosion, the possibility of more infringers and disruption to [its] business in terms of personnel and research resulting from such competition and the associated reduction of revenues." *See Glasstech, Inc. v. AB Kyro OY*, 635 F. Supp. 465, 468, 29 U.S.P.Q. 145, 147 (N.D. Ohio 1986).

Since 1994 Halliburton has created its market for the Patented tools, however, Defendants only recently have begun selling their infringing tools. *See 3M Unitek Corp. v.*

Ormco Co., 96 F.Supp.2d 1042, 1051-52 (C.D. Cal. 2000) ("[T]he fact that plaintiffs have invested more time and effort into marketing their patented invention also weighs in favor of plaintiffs).

E. THE PUBLIC INTEREST FAVORS THE GRANTING OF AN INJUNCTION AGAINST WEATHERFORD AND BJ

"[P]ublic policy favors protection of the rights secured by the valid patents." *Smith Int'l*, 718 F.2d at 1581. Only when "there exists some critical public interest that would be injured by the grant of preliminary relief" does the public interest favor denial of an injunction. *Hybritech*, 849 F.2d at 1458. There are no such critical public interests involved here.

IV. NO BOND IS NECESSARY HERE

Pursuant to Fed. R. Civ. P. 65(c), Halliburton requests that the Court require no bond.[5] Because Halliburton has made a strong showing of likelihood of success on the merits, a bond is unnecessary. *Kaepa, Inc. v. Achilles Corp.*, 76 F.3rd 624, 628 (5th Cir. 1996).

V. CONCLUSION

Halliburton has demonstrated all the requisite factors favoring issuance of a temporary restraining order and a preliminary injunction enjoining Defendants from further infringement. Based on this strong showing, Defendants should be enjoined from making, using, selling, or offering for sale their infringing "FracGuard" and "Python" tools and related services.

[5] Regional circuit law controls issues relating to the setting of injunction bonds. *Xeta, Inc. v. Atex*, Inc. 852 F.2d 1280, 7 U.S.P.Q.2d 1887 (Fed Cir. 1988).

Dated: June _____, 2002

CRUTSINGER & BOOTH

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CERTIFICATE OF CONFERENCE

Plaintiff has conferred with Defendants' counsel Scott Brown, Weatherford International, Inc., 515 Post Oak Blvd., Suite 600, Houston, TX 77027, (713) 693-4176, and Margaret A. Kirick, BJ Services Company, 5500 Northwest Central Drive, Houston, TX 77092, (713) 895-5657 regarding this Motion, and Defendants' counsel oppose said Motion.

DATED: June 27, 2002

J. F. Booth

John F. Booth

CERTIFICATE OF SERVICE

I hereby certify that on this 27 day of June, 2002, a true and correct copy of the within document was caused to be served on the attorneys of record at the following addresses as indicated:

BY HAND DELIVERY Weatherford International, Inc	Scott Brown Patent Counsel Weatherford International, Inc. 515 Post Oak Blvd., Suite 600 Houston, TX 77027 (o) 713-693-4176 (f) 713-693-4480 Attorney for Defendant Weatherford International, Inc.
BY HAND DELIVERY BJ Services Company	Margaret A. Kirick Chief Patent Counsel BJ Services Company 5500 Northwest Central Drive Houston, TX 77092 (o) 713-895-5657 (f) 713-895-5657 Attorneys for Defendant BJ Services Company

John F. Booth

John F. Booth

IN THE UNITED STATES DISTRICT COURT
FOR THE NORTHERN DISTRICT OF TEXAS
DALLAS DIVISION

HALLIBURTON ENERGY SERVICES, INC., Plaintiff, v. WEATHERFORD INTERNATIONAL, INC. and BJ SERVICES COMPANY, Defendants.	CIVIL ACTION NO.____________

APPENDIX

APPENDIX	DESCRIPTION	PAGES
1	**'468 PATENT** **U.S. Patent No. 5,271,468 issued Dec. 21, 1993**	**1-18**
2	**'540 PATENT** **U.S. Patent No. 5,224,540 issued Jul. 6, 1993**	**19-36**
3	**Certificate of Name Change to Halliburton Energy Services, Inc., Dec. 12, 1996**	**37-55**
4	**Declaration of Wesley Jay Burris, II (Product Mgr. for Tools & Testing for Halliburton, incl. the "FAS Drill" tools & services);** **Attaching:** **Ex. A., Halliburton's "FAS Drill" product sheets,** **Ex. B., Weatherford's "Packer Systems" internet website page,**	**56-97** **67-72** **73-74**

	Ex. C., BJ's "Service Tools" internet website page, and Ex. D., BJ's "Python" Bridge Plug Power Point presentation.	75-76 77-97
5	Declaration of Harold E. McGowen, III Attaching: Ex. A., McGowen resume, Ex. B., Weatherford's website advertising for "FracGuard" plugs, Ex. C., Weatherford's "FracGuard" advertisement drawing, tool parts marked, Ex. D., BJ's website advertising for "Python" bridge plug, and Ex. E., BJ's "Python" bridge plug advertisement drawing, tool parts marked.	98-114 105-109 110-111 112 113 114
6	Baker, *A Primer of Oil Well Drilling*, pp. 151-6 (6th Ed. 2001)	115A-120
7	'202 PATENT U.S. Patent No. 4,708,202	121-136
8	LONG, *Improved Completion Method for Mesaverde-Meeteetse Wells in the Wind River Basin*, SPE 60312 (1999)	137-144
9	EBERHARD, *The Effect of Stimulation Methodologies on Production in the Jonah Field*, SPE 71048 (2001)	145-153
10	TOOL SIMULATOR LITE (Halliburton 2001) CD with instruction sheet	154
11	'468 Claim Chart, Claim 1	155-157
12	'468 Claim Chart, Claim 30	158-160
13	'540 Claim Chart, Claim 3	161-163
14	Baker Oil Tools, Inc., advertisement, WORLD OIL, June 1968, at 137	164-166

15	<u>Special Products Manual</u>: **"Baker Prime Fiberglass Packer", April 25, 1968**	**167-168**
16	**SAVAGE, *Taking New Materials Downhole – The Composite Bridge Plug,* PNEC 662,935 (1994)**	**169-172**
17	**GUOYNES, *New Composite Fracturing Plug Improves Efficiency in Coalbed Methane Completions,* SPE 40052 (1998)**	**173-183**

The United States of America

The Commissioner of Patents and Trademarks

Has received an application for a patent for a new and useful invention. The title and description of the invention are enclosed. The requirements of law have been complied with, and it has been determined that a patent on the invention shall be granted under the law.

Therefore, this

United States Patent

Grants to the person or persons having title to this patent the right to exclude others from making, using or selling the invention throughout the United States of America for the term of seventeen years from the date of this patent, subject to the payment of maintenance fees as provided by law.

Bruce Lehman

Commissioner of Patents and Trademarks

Priscilla A Fuller

Attest

US005271468A

United States Patent [19]

Streich et al.

[11] **Patent Number: 5,271,468**

[45] **Date of Patent: Dec. 21, 1993**

[54] **DOWNHOLE TOOL APPARATUS WITH NON-METALLIC COMPONENTS AND METHODS OF DRILLING THEREOF**

[75] Inventors: Steven G. Streich; Donald F. Hushbeck; Kevin T. Berscheidt; Rick D. Jacobi, all of Duncan, Okla.

[73] Assignee: Halliburton Company, Duncan, Okla.

[21] Appl. No.: 719,740

[22] Filed: Jun. 21, 1991

Related U.S. Application Data

[63] Continuation-in-part of Ser. No. 515,019, Apr. 26, 1990, abandoned.

[51] Int. Cl.[5] E21B 33/129

[52] U.S. Cl. 166/387; 166/118; 166/134; 166/217; 166/376; 175/57

[58] Field of Search 166/376, 387, 118, 135, 166/134, 138, 179, 192, 382, 123, 128, 242; 175/57

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Chapter 4, Fundamentals of Drilling, by John L. Kennedy, PennWell Books, Copyright 1983.

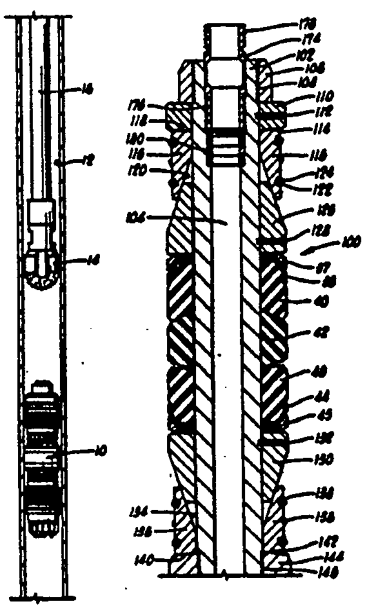
"Molding Compounds Materials Selection Handbook", published by Fiberite Corporation, Copyright, 1986.

Primary Examiner—Stephen J. Novosad

[57] **ABSTRACT**

A downhole tool apparatus and methods of drilling the apparatus. The apparatus may include, but is not limited to, packers and bridge plugs utilizing non-metallic components. The material may include engineering grade plastics. The nonmetallic components may include but are not limited to the center mandrel, slips, slip wedges, slip supports and housings, spacer rings, valve housings and valve components. Methods of drilling out the apparatus without significant variations in the drilling speed and weight applied to the drill bit may be employed. Alternative drill bit types, such as polycrystalline diamond compact (PDC) bits may also be used.

75 Claims, 6 Drawing Sheets



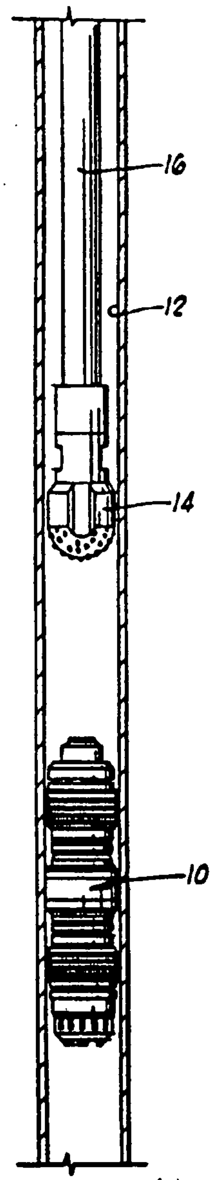

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FIG. 1

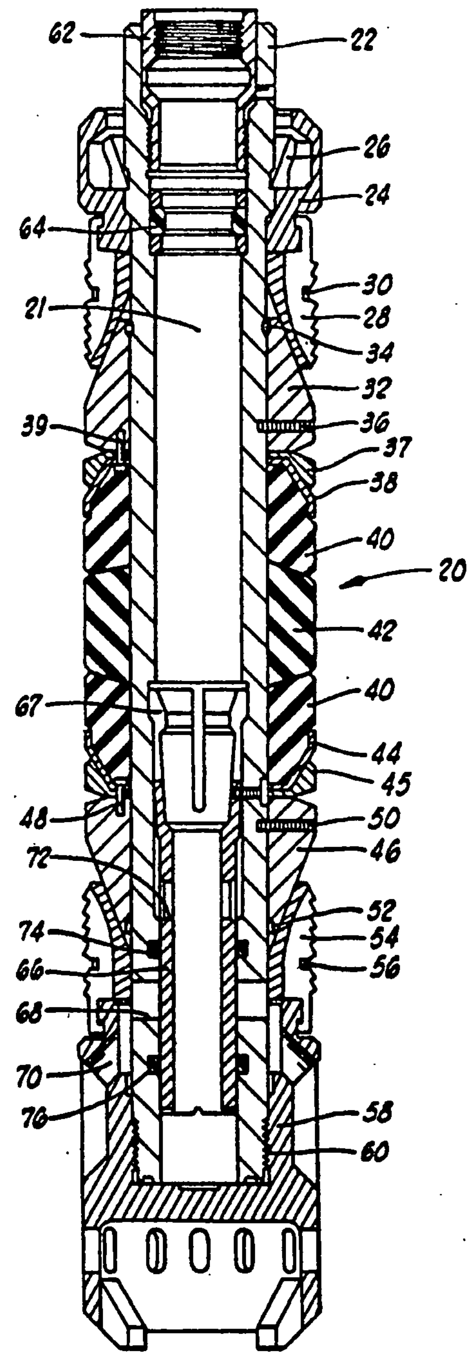
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FIG. 2

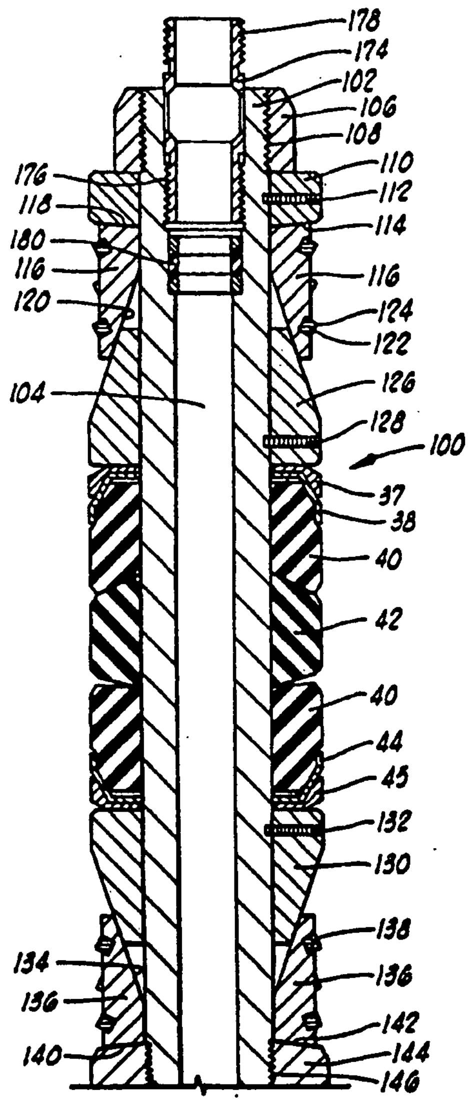
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FIG. 3A

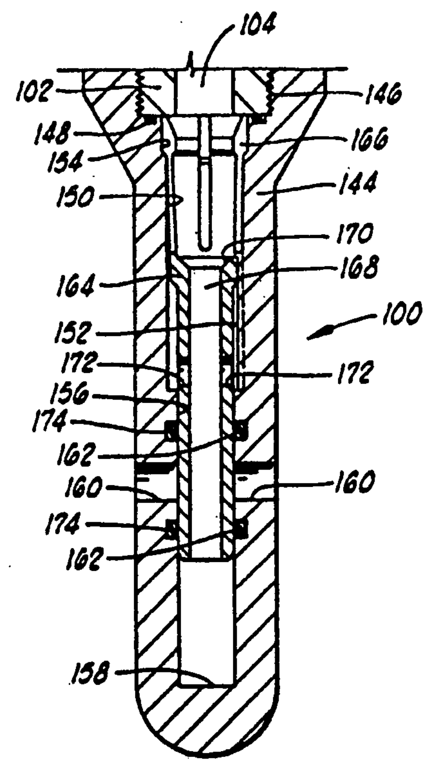
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FIG. 3B

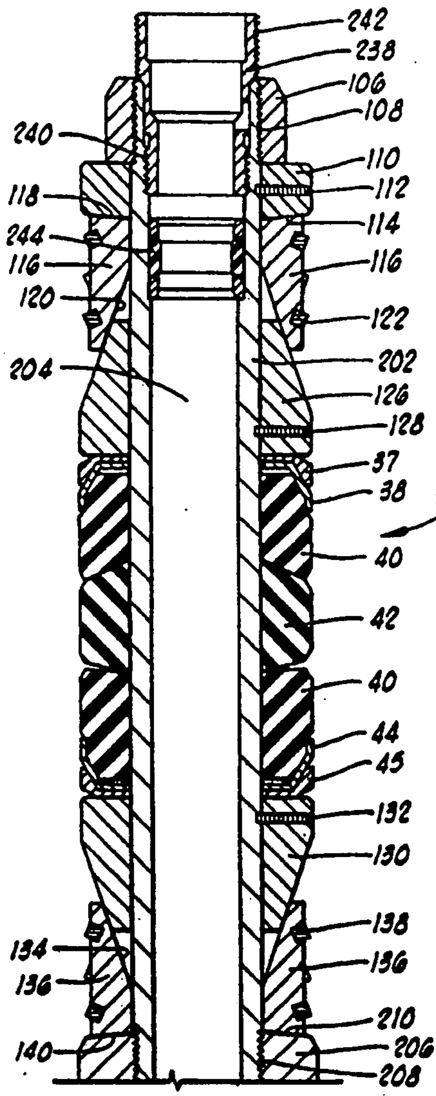
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FIG. 4A

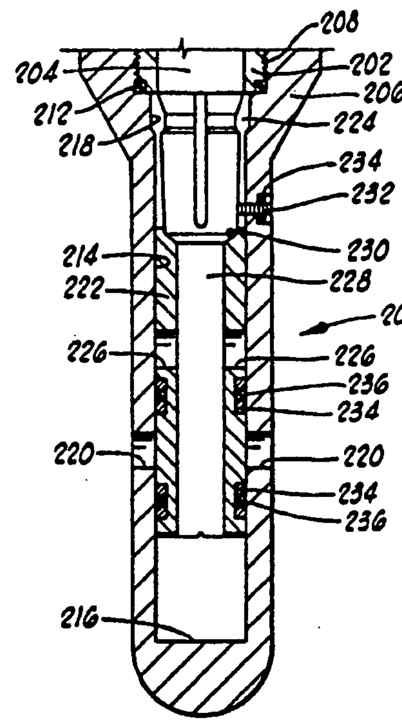
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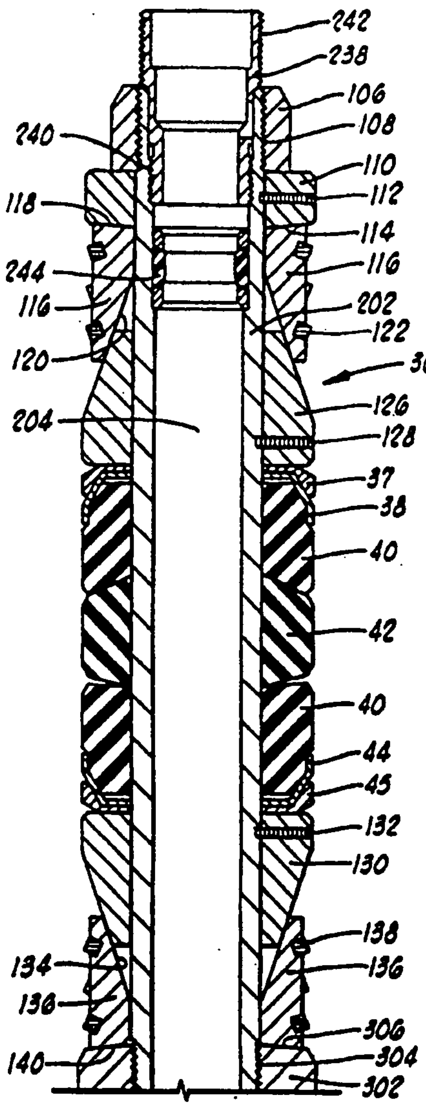
FIG. 4B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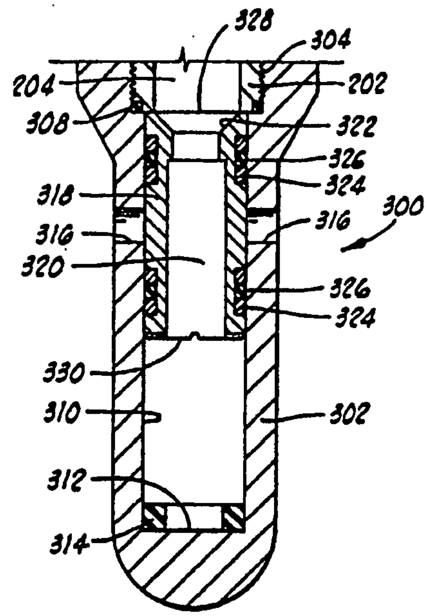
116
116
202
122
120
300
204
126
128
37
38
40
42
40
44
45
132
130
138
134
136
136
306
140
304
302

FIG. 5A


328
304
204
202
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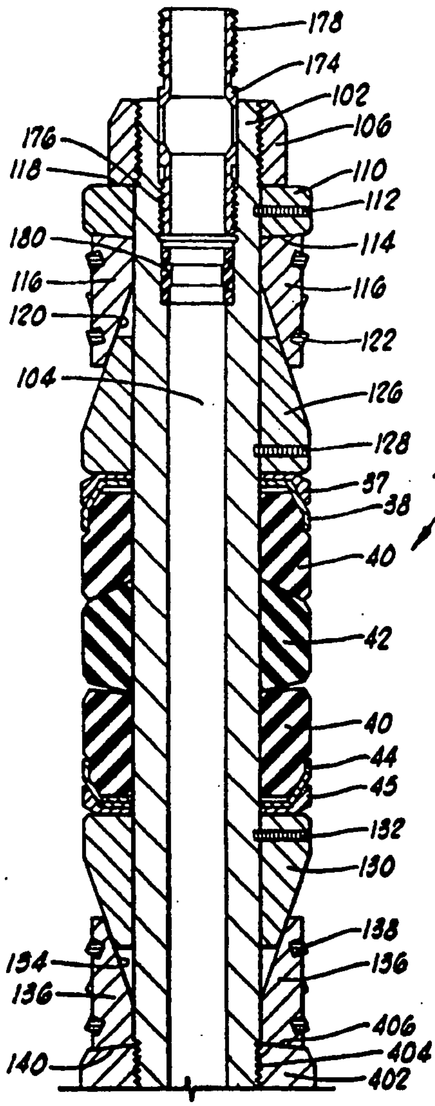
322
326
324
318
316
316
300
320
326
324
330
310
302
312
314

FIG. 5B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174
102
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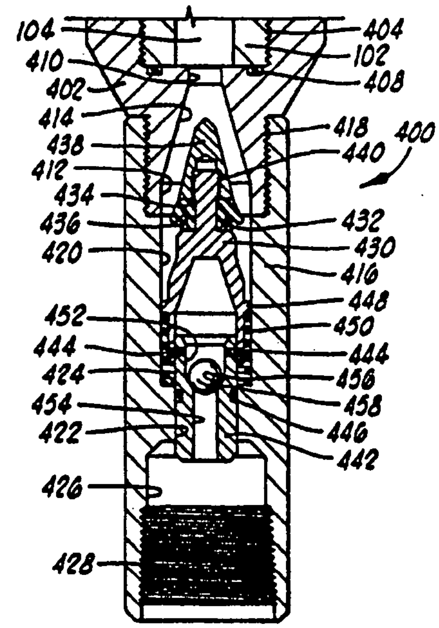
176
118
110
112
180
114
116
116
120
122
104
126
128
37
400
38
40
42
40
44
45
132
130
138
134
136
136
406
404
140
402

FIG. 6A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404
102
410
408
402
414
418
400
438
440
412
434
432
436
430
420
416
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452
450
444
444
424
456
454
458
422
446
442
426
428

FIG. 6B

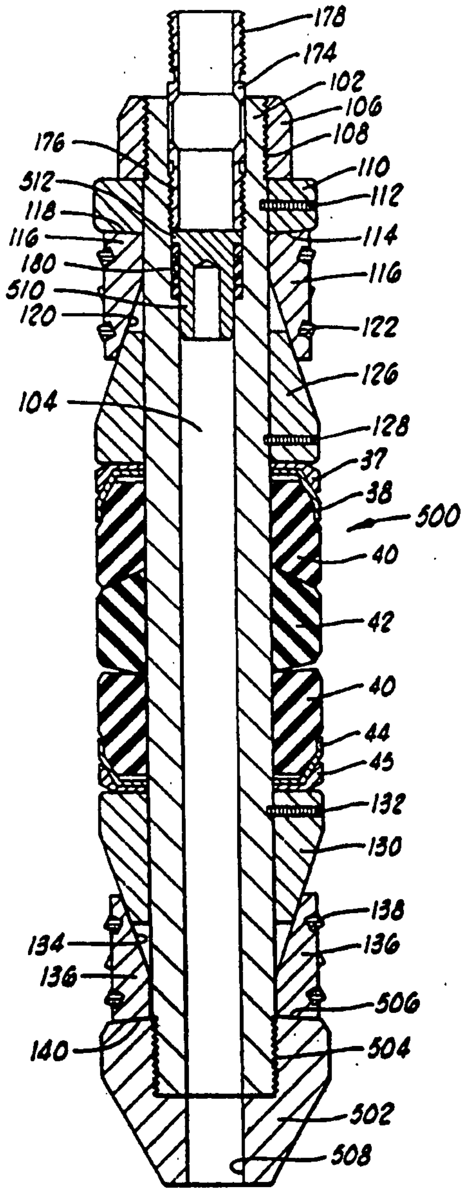
178
174
102
106
108
176
110
312
112
118
114
116
116
180
510
120
122
126
104
128
37
38
500
40
42
40
44
45
132
130
138
134
136
136
506
140
504
502
508

FIG. 7

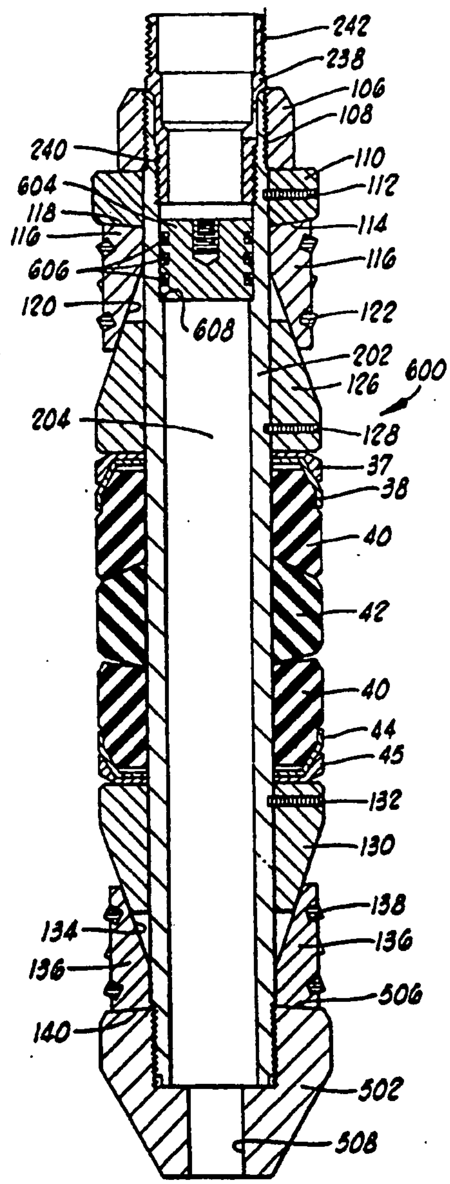
242
238
106
108
240
110
604
112
118
114
116
116
606
120
122
608
202
600
126
204
128
37
38
40
42
40
44
45
132
130
138
134
136
136
506
140
502
508

FIG. 8

DOWNHOLE TOOL APPARATUS WITH NON-METALLIC COMPONENTS AND METHODS OF DRILLING THEREOF

This application is a continuation-in-part of co-pending application Ser. No. 07/515,019, filed Apr. 26, 1990 now abandoned.

BACKGROUND OF THE INVENTION

1. Field Of The Invention

This invention relates to downhole tools for use in well bores and methods of drilling such apparatus out of well bores, and more particularly, to such tools having drillable components therein made of non-metallic materials, such as engineering grade plastics.

2. Description Of The Prior Art

In the drilling or reworking of oil wells, a great variety of downhole tools are used. For example, but not by way of limitation, it is often desirable to seal tubing or other pipe in the casing of the well, such as when it is desired to pump cement or other slurry down tubing and force the slurry out into a formation. It then becomes necessary to seal the tubing with respect to the well casing and to prevent the fluid pressure of the slurry from lifting the tubing out of the well. Packers and bridge plugs designed for these general purposes are well known in the art.

When it is desired to remove many of these downhole tools from a well bore, it is frequently simpler and less expensive to mill or drill them out rather than to implement a complex retrieving operation. In milling, a milling cutter is used to grind the packer or plug, for example, or at least the outer components thereof, out of the well bore. Milling is a relatively slow process, but it can be used on packers or bridge plugs having relatively hard components such as erosion-resistant hard steel. One such packer is disclosed in U.S. Pat. No. 4,151,875 to Sullaway, assigned to the assignee of the present invention and sold under the trademark EZ Disposal packer. Other downhole tools in addition to packers and bridge plugs may also be drilled out.

In drilling, a drill bit is used to cut and grind up the components of the downhole tool to remove it from the well bore. This is a much faster operation than milling, but requires the tool to be made out of materials which can be accommodated by the drill bit. Typically, soft and medium hardness cast iron are used on the pressure bearing components, along with some brass and aluminum items. Packers of this type include the Halliburton EZ Drill ® and EZ Drill SV ® squeeze packers.

The EZ Drill SV ® squeeze packer, for example, includes a lock ring housing, upper slip wedge, lower slip wedge, and lower slip support made of soft cast iron. These components are mounted on a mandrel made of medium hardness cast iron. The EZ Drill ® squeeze packer is similarly constructed. The Halliburton EZ Drill ® bridge plug is also similar, except that it does not provide for fluid flow therethrough.

All of the above-mentioned packers are disclosed in Halliburton Services Sales and Service Catalog No. 43, pages 2561–2562, and the bridge plug is disclosed in the same catalog on pages 2556–2557.

The EZ Drill ® packer and bridge plug and the EZ Drill SV ® packer are designed for fast removal from the well bore by either rotary or cable tool drilling methods. Many of the components in these drillable packing devices are locked together to prevent their spinning while being drilled, and the harder slips are grooved so that they will be broken up in small pieces. Typically, standard "tri-cone" rotary drill bits are used which are rotated at speeds of about 75 to about 120 rpm. A load of about 5,000 to about 7,000 pounds of weight is applied to the bit for initial drilling and increased as necessary to drill out the remainder of the packer or bridge plug, depending upon its size. Drill collars may be used as required for weight and bit stabilization.

Such drillable devices have worked well and provide improved operating performance at relatively high temperatures and pressures. The packers and plug mentioned above are designed to withstand pressures of about 10,000 psi and temperatures of about 425° F. after being set in the well bore. Such pressures and temperatures require the cast iron components previously discussed.

However, drilling out iron components requires certain techniques. Ideally, the operator employs variations in rotary speed and bit weight to help break up the metal parts and reestablish bit penetration should bit penetration cease while drilling. A phenomenon known as "bit tracking" can occur, wherein the drill bit stays on one path and no longer cuts into the downhole tool. When this happens, it is necessary to pick up the bit above the drilling surface and rapidly recontact the bit with the packer or plug and apply weight while continuing rotation. This aids in breaking up the established bit pattern and helps to reestablish bit penetration. If this procedure is used, there are rarely problems. However, operators may not apply these techniques or even recognize when bit tracking has occurred. The result is that drilling times are greatly increased because the bit merely wears against the surface of the downhole tool rather than cutting into it to break it up.

While cast iron components may be necessary for the high pressures and temperatures for which they are designed, it has been determined that many wells experience pressures less than 10,000 psi and temperatures less than 425° F. This includes most wells cemented. In fact, in the majority of wells, the pressure is less than about 5,000 psi, and the temperature is less than about 250° F. Thus, the heavy duty metal construction of the previous downhole tools, such as the packers and bridge plugs described above, is not necessary for many applications, and if cast iron components can be eliminated or minimized, the potential drilling problems resulting from bit tracking might be avoided as well.

The downhole tool of the present invention solves this problem by providing an apparatus wherein at least some of the components, including pressure bearing components, are made of non-metallic materials, such as engineering grade plastics. Such plastic components are much more easily drilled than cast iron, and new drilling methods may be employed which use alternative drill bits such as polycrystalline diamond compact bits, or the like, rather than standard tri-cone bits.

SUMMARY OF THE INVENTION

The downhole tool apparatus of the present invention utilizes non-metallic materials, such as engineering grade plastics, to reduce weight, to reduce manufacturing time and labor, to improve performance through reducing frictional forces of sliding surfaces, to reduce costs and to improve drillability of the apparatus when drilling is required to remove the apparatus from the well bore. Primarily, in this disclosure, the downhole

tool is characterized by well bore packing apparatus, but it is not intended that the invention be limited to such packing devices. The non-metallic components in the downhole tool apparatus also allow the use of alternative drilling techniques to those previously known.

In packing apparatus embodiments of the present invention, the apparatus may utilize the same general geometric configuration of previously known drillable packers and bridge plugs while replacing at least some of the metal components with non-metallic materials which can still withstand the pressures and temperatures exposed thereto in many well bore applications. In other embodiments of the present invention, the apparatus may comprise specific design changes to accommodate the advantages of plastic materials and also to allow for the reduced strengths thereof compared to metal components.

In one embodiment of the downhole tool, the invention comprises a center mandrel and slip means disposed on the mandrel for grippingly engaging the well bore when in a set position. In packing embodiments, the apparatus further comprises a packing means disposed on the mandrel for sealingly engaging the well bore when in a set position.

The slip means may comprise a wedge engaging a plurality of slips with a slip support on the opposite side of the slips from the wedge. Any of the mandrel, slips, slip wedges or slip supports may be made of the non-metallic material, such as plastic. Specific plastics include nylon, phenolic materials and epoxy resins. The phenolic materials may further include any of Fiberite FM4056J, Fiberite FM4005 or Resinoid 1360. The plastic components may be molded or machined.

One preferred plastic material for at least some of these components is a glass reinforced phenolic resin having a tensile strength of about 18,000 psi and a compressive strength of about 40,000 psi, although the invention is not intended to be limited to this particular plastic or a plastic having these specific physical properties. The plastic materials are preferably selected such that the packing apparatus can withstand well pressures less than about 10,000 psi and temperatures less than about 425° F. In one preferred embodiment, but not by way of limitation, the plastic materials of the packing apparatus are selected such that the apparatus can withstand well pressures up to about 5,000 psi and temperatures up to about 250° F.

Most of the components of the slip means are subjected to substantially compressive loading when in a sealed operating position in the well bore, although some tensile loading may also be experienced. The center mandrel typically has tensile loading applied thereto when setting the packer and when the packer is in its operating position.

One new method of the invention is a well bore process comprising the steps of positioning a downhole tool into engagement with the well bore; prior to the step of positioning, constructing the tool such that a component thereof is made of a non-metallic material; and then drilling the tool out of the well bore. The tool may be selected from the group consisting packers and bridge plugs, but is not limited to these devices.

The component made of non-metallic material, may be one of several such components. The components may be substantially subject to compressive loading. Such components in the tool may include lock ring housings, slips, slip wedges and slip supports. Some components, such as center mandrels of such tools may be substantially subjected to tensile loading.

In another embodiment, the step of drilling is carried out using a polycrystalline diamond compact bit. Regardless of the type of drill bit used, the process may further comprise the step of drilling using a drill bit without substantially varying the weight applied to the drill bit.

In another method of the invention, a well bore process comprises the steps of positioning and setting a packing device in the well bore, a portion of the device being made of engineering grade plastic; contacting the device with well fluids; and drilling out the device using a drill bit having no moving parts such as a polycrystalline diamond compact bit. This or a similar drill bit might have been previously used in drilling the well bore itself, so the process may be said to further comprise the step of, prior to the step of positioning and setting the packer, drilling at least a portion of the well bore using a drill bit such as a polycrystalline diamond compact bit.

In one preferred embodiment, the step of contacting the packer is at a pressure of less than about 5,000 psi and a temperature of less than about 250° F, although higher pressures and temperatures may also be encountered.

It is an important object of the invention to provide a downhole tool apparatus utilizing components made of nonmetallic materials and methods of drilling thereof.

It is another object of the invention to provide a well bore packing apparatus using components made of engineering grade plastic.

An additional object of the invention is to provide a packing apparatus having a valve housing disposed substantially below a lower end of a center mandrel and having a valve in the valve housing below the lower end of the center mandrel.

It is a further object of the invention to provide a packing apparatus which may be drilled by alternate methods to those using standard rotary drill bits.

Additional objects and advantages of the invention will become apparent as the following detailed description of the preferred embodiments is read in conjunction with the drawings which illustrate such preferred embodiments.

BRIEF DESCRIPTION OF THE DRAWINGS

FIG. 1 generally illustrates the downhole tool of the present invention positioned in a well bore with a drill bit disposed thereabove.

FIG. 2 illustrates a cross section of one embodiment of a drillable packer made in accordance with the invention.

FIGS. 3A and 3B show a cross section of a second embodiment of a drillable packer.

FIGS. 4A and 4B show a third drillable packer embodiment.

FIGS. 5A and 5B illustrate a fourth embodiment of a drillable packer.

FIGS. 6A and 6B show a fifth drillable packer embodiment with a poppet valve therein.

FIG. 7 shows a cross section of one embodiment of a drillable bridge plug made in accordance with the present invention.

FIG. 8 illustrates a second embodiment of a drillable bridge plug.

DESCRIPTION OF THE PREFERRED EMBODIMENT

Referring now to the drawings, and more particularly to FIG. 1, the downhole tool apparatus of the present invention is shown and generally designated by the numeral 10. Apparatus 10, which may include, but is not limited to, packers, bridge plugs, or similar devices, is shown in an operating position in a well bore 12. Apparatus 10 can be set in this position by any manner known in the art such as setting on a tubing string or wire line. A drill bit 14 connected to the end of a tool or tubing string 16 is shown above apparatus 10 in a position to commence the drilling out of apparatus 10 from well bore 12. Methods of drilling will be further discussed herein.

First Packer Embodiment

Referring now to FIG. 2, the details of a first squeeze packer embodiment 20 of apparatus 10 will be described. The size and configuration of packer 20 is substantially the same as the previously mentioned prior art EZ Drill SV® squeeze packer. Packer 20 defines a generally central opening 21 therein.

Packer 20 comprises a center mandrel 22 on which most of the other components are mounted. A lock ring housing 24 is disposed around an upper end of mandrel 22 and generally encloses a lock ring 26.

Disposed below lock ring housing 24 and pivotally connected thereto are a plurality of upper slips 28 initially held in place by a retaining band 30. A generally conical upper slip wedge is disposed around mandrel 22 adjacent to upper slips 30. Upper slip wedge 32 is held in place on mandrel 22 by a wedge retaining ring 34 and a plurality of screws 36.

Adjacent to the lower end of upper slip wedge 32 is an upper back-up ring 37 and an upper packer shoe 38 connected to the upper slip wedge by a pin 39. Below upper packer shoe 38 are a pair of end packer elements 40 separated by center packer element 42. A lower packer shoe 44 and lower back-up ring 45 are disposed adjacent to the lowermost end packer element 40.

A generally conical lower slip wedge 46 is positioned around mandrel 22 adjacent to lower packer shoe 44, and a pin 48 connects the lower packer shoe to the lower slip wedge.

Lower slip wedge 46 is initially attached to mandrel 22 by a plurality of screws 50 and a wedge retaining ring 52 in a manner similar to that for upper slip wedge 32. A plurality of lower slips 54 are disposed adjacent to lower slip wedge 46 and are initially held in place by a retaining band 56. Lower slips 54 are pivotally connected to the upper end of a lower slip support 58. Mandrel 22 is attached to lower slip support 58 at threaded connection 60.

Disposed in mandrel 22 at the upper end thereof is a tension sleeve 62 below which is an internal seal 64. Tension sleeve 62 is adapted for connection with a setting tool (not shown) of a kind known in the art.

A collet-latch sliding valve 66 is slidably disposed in central opening 21 at the lower end of mandrel 22 adjacent to fluid ports 68 in the mandrel. Fluid ports 68 in mandrel 22 are in communication with fluid ports 70 in lower slip housing 58. The lower end of lower slip support 58 is closed below ports 70.

Sliding valve 66 defines a plurality of valve ports 72 which can be aligned with fluid ports 68 in mandrel 22 when sliding valve 66 is in an open position. Thus, fluid can flow through central opening 21.

On the upper end of sliding valve 66 are a plurality of collet fingers 67 which are adapted for latching and unlatching with a valve actuation tool (not shown) of a kind known in the art. This actuation tool is used to open and close sliding valve 66 as further discussed herein. As illustrated in FIG. 2, sliding valve 66 is in a closed position wherein fluid ports 68 are sealed by upper and lower valve seals 74 and 76.

In prior art drillable packers and bridge plugs of this type, mandrel 22 is made of a medium hardness cast iron, and lock ring housing 24, upper slip wedge 32, lower slip wedge 46 and lower slip support 58 are made of soft cast iron for drillability. Most of the other components are made of aluminum, brass or rubber which, of course, are relatively easy to drill. Prior art upper and lower slips 28 and 54 are made of hard cast iron, but are grooved so that they will easily be broken up in small pieces when contacted by the drill bit during a drilling operation.

As previously described, the soft cast iron construction of prior art lock ring housings, upper and lower slip wedges, and lower slip supports are adapted for relatively high pressure and temperature conditions, while a majority of well applications do not require a design for such conditions. Thus, the apparatus of the present invention, which is generally designed for pressures lower than 10,000 psi and temperatures lower than 425° F., utilizes engineering grade plastics for at least some of the components. For example, the apparatus may be designed for pressures up to about 5,000 psi and temperatures up to about 250° F., although the invention is not intended to be limited to these particular conditions.

In first packer embodiment 20, at least some of the previously soft cast iron components of the slip means, such as lock ring housing 24, upper and lower slip wedges 32 and 46 and lower slip support 58 are made of engineering grade plastics. In particular, upper and lower slip wedges 32 and 46 are subjected to substantially compressive loading. Since engineering grade plastics exhibit good strength in compression, they make excellent choices for use in components subjected to compressive loading. Lower slip support 58 is also subjected to substantially compressive loading and can be made of engineering grade plastic when packer 20 is subjected to relative low pressures and temperatures.

Lock ring housing 24 is mostly in compression, but does exhibit some tensile loading. However, in most situations, this tensile loading is minimal, and lock ring housing 24 may also be made of an engineering grade plastic of substantially the same type as upper and lower slip wedges 32 and 46 and also lower slip housing 58.

Upper and lower slips 28 and 54 may also be of plastic in some applications. Hardened inserts for gripping well bore 12 when packer 20 is set may be required as part of the plastic slips. Such construction is discussed in more detail herein for other embodiments of the invention.

Lock ring housing 24, upper slip wedge 32, lower slip wedge 46, and lower slip housing 58 comprise approximately 75% of the cast iron of the prior art squeeze packers. Thus, replacing these components with similar components made of engineering grade plastics will enhance the drillability of packer 20 and reduce the time and cost required therefor.

Mandrel 22 is subjected to tensile loading during setting and operation, and many plastics will not be acceptable materials therefor. However, some engineer-

ing plastics exhibit good tensile loading characteristics, so that construction of mandrel 22 from such plastics is possible. Reinforcements may be provided in the plastic resin as necessary.

EXAMPLE

A first embodiment packer 20 was constructed in which upper slip wedge 32 and lower slip wedge 46 were constructed by molding the parts to size from a phenolic resin plastic with glass reinforcement. The specific material used was Fiberite 4056J manufactured by Fiberite Corporation of Winona, Minn. This material is classified by the manufacturer as a two stage phenolic with glass reinforcement. It has a tensile strength of 18,000 psi and a compressive strength of 40,000 psi.

The test packer 20 held to 8,500 psi without failure to wedges 32 and 46, more than sufficient for most well bore conditions.

Second Packer Embodiment

Referring now to FIGS. 3A and 3B, the details of a second squeeze packer embodiment 100 of packing apparatus 10 are shown. While first embodiment 20 incorporates the same configuration and general components as prior art packers made of metal, second packer embodiment 100 and the other embodiments described herein comprise specific design features to accommodate the benefits and problems of using non-metallic components, such as plastic.

Packer 100 comprises a center mandrel 102 on which most of the other components are mounted. Mandrel 102 may be described as a thick cross-sectional mandrel having a relatively thicker wall thickness than typical packer mandrels, including center mandrel 22 of first embodiment 20. A thick cross-sectional mandrel may be generally defined as one in which the central opening therethrough has a diameter less than about half of the outside diameter of the mandrel. That is, mandrel central opening 104 in central mandrel 102 has a diameter less than about half the outside of center mandrel 102. It is contemplated that a thick cross-sectional mandrel will be required if it is constructed from a material having relatively low physical properties. In particular, such materials may include phenolics and similar plastic materials.

An upper support 106 is attached to the upper end of center mandrel 102 at threaded connection 108. In an alternate embodiment, center mandrel 102 and upper support 106 are integrally formed and there is no threaded connection 108. A spacer ring or upper slip support 110 is disposed on the outside of mandrel 102 just below upper support 106. Spacer ring 110 is initially attached to center mandrel 102 by at least one shear pin 112. A downwardly and inwardly tapered shoulder 114 is defined on the lower side of spacer ring 110.

Disposed below spacer ring 110 are a plurality of upper slips 116. A downwardly and inwardly sloping shoulder 118 forms the upper end of each slip 116. The taper of each shoulder 118 conforms to the taper of shoulder 114 on spacer ring 110, and slips 116 are adapted for sliding engagement with shoulder 114, as will be further described herein.

An upwardly and inwardly facing taper 120 is defined in the lower end of each slip 116. Each taper 120 generally faces the outside of center mandrel 102.

A plurality of hardened inserts or teeth 122 preferably are molded into upper slips 116. In the embodiment shown in FIG. 3A, inserts 122 have a generally square cross section and are positioned at an angle so that a radially outer edge 124 protrudes from the corresponding upper slip 116. Outer edge 124 is adapted for grippingly engaging well bore 112 when packer 100 is set. It is not intended that inserts 122 be of square cross section and have a distinct outer edge 124. Different shapes of inserts may also be used. Inserts 122 can be made of any suitable hardened material.

An upper slip wedge 126 is disposed adjacent to upper slips 116 and engages taper 120 therein. Upper slip wedge 126 is initially attached to center mandrel 102 by one or more shear pins 128.

Below upper slip wedge 126 are upper back-up ring 37, upper packer shoe 38, end packer elements 40 separated by center packer element 42, lower packer shoe 44 and lower back-up ring 45 which are substantially the same as the corresponding components in first embodiment packer 20. Accordingly, the same reference numerals are used.

Below lower back-up ring 45 is a lower slip wedge 130 which is initially attached to center mandrel 102 by a shear pin 132. Preferably, lower slip wedge 130 is identical to upper slip wedge 126 except that it is positioned in the opposite direction.

Lower slip wedge 130 is in engagement with an inner taper 134 in a plurality of lower slips 136. Lower slips 136 have inserts or teeth 138 molded therein, and preferably, lower slips 136 are substantially indentical to upper slips 116.

Each lower slip 136 has a downwardly facing shoulder 140 which tapers upwardly and inwardly. Shoulders 140 are adapted for engagement with a corresponding shoulder 142 defining the upper end of a valve housing 144. Shoulder 142 also tapers upwardly and inwardly. Thus, valve housing 144 may also be considered a lower slip support 144.

Referring now also to FIG. 3B, valve housing 146 is attached to the lower end of center mandrel 102 at threaded connection 146. A sealing means, such as O-ring 148, provides sealing engagement between valve housing 144 and center mandrel 102.

Below the lower end of center mandrel 102, valve housing 104 defines a longitudinal opening 150 therein having a longitudinal rib 152 in the lower end thereof. At the upper end of opening 150 is an annular recess 154.

Below opening 150, valve housing 144 defines a housing central opening including a bore 156 therein having a closed lower end 158. A plurality of transverse ports 160 are defined through valve housing 144 and intersect bore 156. The wall thickness of valve housing 144 is thick enough to accommodate a pair of annular seal grooves 162 defined in bore 156 on opposite sides of ports 160.

Slidably disposed in valve housing 144 below center mandrel 102 is a sliding valve 164. Sliding valve 164 is the same as, or substantially similar to, sliding valve 66 in first embodiment packer 20. At the upper end of sliding valve 164 are a plurality of upwardly extending collet fingers 166 which initially engage recess 154 in valve housing 144. Sliding valve 164 is shown in an uppermost, closed position in FIG. 3B. It will be seen that the lower end of center mandrel 102 prevents further upward movement of sliding valve 164.

Sliding valve 164 defines a valve central opening 168 therethrough which is in communication with central opening 104 in center mandrel 102. A chamfered shoul-

der 170 is located at the upper end of valve central opening 168.

Sliding valve 164 defines a plurality of substantially transverse ports 172 therethrough which intersect valve central opening 168. As will be further discussed herein, ports 172 are adapted for alignment with ports 160 in valve housing 144 when sliding valve 164 is in a downward, open position thereof. Rib 152 fits between a pair of collet fingers 166 so that sliding valve 164 cannot rotate within valve housing 144, thus insuring proper alignment of ports 172 and 160. Rib 152 thus provides an alignment means.

A sealing means, such as O-ring 174, is disposed in each seal groove 162 and provides sealing engagement between sliding valve 164 and valve housing 144. It will thus be seen that when sliding valve 164 is moved downwardly to its open position, O-rings 174 seal on opposite sides of ports 172 in the sliding valve.

Referring again to FIG. 3A, a tension sleeve 174 is disposed in center mandrel 102 and attached thereto to threaded connection 176 Tension sleeve 174 has a threaded portion 178 which extends from center mandrel 102 and is adapted for connection to a standard setting tool (not shown) of a kind known in the art.

Below tension sleeve 174 is an internal seal 180 similar to internal seal 64 in first embodiment 20.

Third Packer Embodiment

Referring now to FIGS. 4A and 4B, a third squeeze packer embodiment of the present invention is shown and generally designated by the numeral 200. It will be clear to those skilled in the art that third embodiment 200 is similar to second packer embodiment 100 but has a couple of significant differences.

Packer 200 comprises a center mandrel 202. Unlike center mandrel 102 in second embodiment 100, center mandrel 202 is a thin cross-sectional mandrel. That is, it may be said that center mandrel 102 has a mandrel central opening 204 with a diameter greater than about half of the outside diameter of center mandrel 202. It is contemplated that thin cross-sectional mandrels, such as center mandrel 202, may be made of materials having relatively higher physical properties, such as epoxy resins.

The external components of third packer embodiment 200 which fit on the outside of center mandrel 202. are substantially identical to the outer components on second embodiment 100, and therefore the same reference numerals are shown in FIG. 4A. In a manner similar to second embodiment packer 100, center mandrel 202 and upper support 106 may be integrally formed so that there is no threaded connection 108.

The lower end of center mandrel 202 is attached to a valve housing 206 at threaded connection 208. On the upper end of valve housing 206 is an upwardly and inwardly tapered shoulder 210 against which shoulder 104 on lower slips 136 are slidably disposed. Thus, valve housing 206 may also be referred to as a lower slip support 206.

Referring now also to FIG. 4B, a sealing means, such as O-ring 212, provides sealing engagement between center mandrel 202 and valve housing 206.

Valve housing 206 defines a housing central opening including a bore 214 therein with a closed lower end 216. At the upper end of bore 214 is an annular recess 218. Valve housing 204 defines a plurality of substantially transverse ports 220 therethrough which intersect bore 214.

Slidably disposed in bore 214 in valve housing 206 is a sliding valve 222. At the upper end of sliding valve 222 are a plurality of collet fingers 224 which initially engage recess 218.

Sliding valve 222 defines a plurality of substantially transverse ports 226 therein which intersect a valve central opening 228 in the sliding valve. Valve central opening 228 is in communication with mandrel central opening 204 in center mandrel 202. At the upper end of central opening 228 is a chamfered shoulder 230.

As shown in FIG. 4B, sliding valve 222 is in an uppermost closed position. It will be seen that the lower end of center mandrel 202 prevents further upward movement of sliding valve 222. When sliding valve 222 is moved downwardly to an open position, ports 226 are substantially aligned with ports 220 in valve housing 206. An alignment means, such as an alignment bolt 232, extends from valve housing 206 inwardly between a pair of adjacent collet fingers 224. A sealing means, such as O-ring 234, provides sealing engagement between alignment bolt 232 and valve housing 206. Alignment bolt 234 prevents rotation of sliding valve 222 within valve housing 204 and insures proper alignment of ports 226 and 220 when sliding valve 222 is in its downwardmost, open position.

The wall thickness of sliding valve 222 is sufficient to accommodate a pair of spaced seal grooves 234 are defined in the outer surface of sliding valve 222, and as seen in FIG. 4B, seal grooves 234 are disposed on opposite sides of ports 220 when sliding valve 222 is in the open position shown. A sealing means, such as seal 236, is disposed in each groove 234 to provide sealing engagement between sliding valve 222 and bore 214 in valve housing 206.

Referring again to FIG. 4A, a tension sleeve 238 is attached to the upper end of center mandrel 202 at threaded connection 240. A threaded portion 242 of tension sleeve 238 extends upwardly from center mandrel 202 and is adapted for engagement with a setting apparatus (not shown) of a kind known in the art.

An internal seal 244 is disposed in the upper end of center mandrel 202 below tension sleeve 238.

Fourth Packer Embodiment

Referring now to FIGS. 5A and 5B, a fourth squeeze packer embodiment is shown and generally designated by the numeral 300. As illustrated, fourth embodiment 300 has the same center mandrel 202, and all of the components positioned on the outside of center mandrel 202 are identical to those in the second and third packer embodiments. Therefore, the same reference numerals are used for these components. Tension sleeve 238 and internal seal 244 positioned on the inside of the upper end of center mandrel 202 are also substantially identical to the corresponding components in third embodiment packer 200 and therefore shown with the same reference numerals.

The difference between fourth packer embodiment 300 and third packer embodiment 200 is that in the fourth embodiment shown in FIGS. 5A and 5B, the lower end of center mandrel 202 is attached to a different valve housing 302 at threaded connection 304. Shoulder 140 on each lower slip 136 slidingly engages an upwardly and inwardly tapered shoulder 306 on the top of valve housing 302. Thus, valve housing 302 may also be referred to as lower slip support 302.

Referring now to FIG. 5B, a sealing means, such as O-ring 308, provides sealing engagement between the lower end of center mandrel 202 and valve housing 302.

Valve housing 302 defines a housing central opening including a bore 310 therein with a closed lower end 312. A bumper seal 314 is disposed adjacent to end 312.

Valve housing 302 defines a plurality of substantially transverse ports 316 therethrough which intersect bore 310. A sliding valve 318 is disposed in bore 310, and is shown in an uppermost, closed position in FIG. 5B. It will be seen that the lower end of center mandrel 202 prevents upward movement of sliding valve 318. Sliding valve 318 defines a valve central opening 320 therethrough which is in communication with mandrel central opening 204 in center mandrel 202. At the upper end of valve central opening 320 in sliding valve 318 is an upwardly facing chamfered shoulder 322.

On the outer surface of sliding valve 318, a pair of spaced seal grooves 324 are defined. In the closed position shown in FIG. 5B, seal grooves 324 are on opposite sides of ports 316 in valve housing 302. A sealing means, such as seal 326, is disposed in each seal groove 324 and provides sealing engagement between sliding valve 318 and bore 310 in valve housing 302.

When sliding valve 318 is opened, as will be further described herein, the sliding valve 318 is moved downwardly such that upper end 328 thereof is below ports 316 in valve housing 302. Downward movement of sliding valve 318 is checked when lower end 330 thereof contacts bumper seal 314. Bumper seal 314 is made of a resilient material which cushions the impact of sliding valve 318 thereon.

Fifth Packer Embodiment

Referring now to FIGS. 6A and 6B, a fifth squeeze packer embodiment is shown and generally designated by the numeral 400. As illustrated, fifth packer embodiment 400 incorporates the same thick cross-sectional center mandrel 102 as does second packer embodiment 100 shown in FIGS. 3A and 3B. Also, the external components positioned on center mandrel 102 are the same as in the second, third and fourth packer embodiments, so the same reference numerals will be used. Further, tension sleeve 174 and internal seal 180 in second embodiment 100 are also incorporated in fifth embodiment 400, and therefore these same reference numerals have also been used.

The difference between fifth packer embodiment 400 and second embodiment 100 is that the lower end of center mandrel 102 is attached to a lower slip support 402 at threaded connection 404. Shoulders 140 on lower slips 136 slidingly engage an upwardly and inwardly tapered shoulder 406 at the upper end of lower slip support 402.

Referring now to FIG. 6B, a sealing means, such as O-ring 408, provides sealing engagement between the lower end of center mandrel 102 and lower slip support 402.

Lower slip support 402 defines a first bore 410 therein and a larger second bore 412 spaced downwardly from the first bore. A tapered seat surface 414 extends between first bore 410 and second bore 412.

The lower end of lower support 402 is attached to a valve housing 416 at threaded connection 418. Valve housing 416 defines a first bore 420 and a smaller second bore 422 therein. An upwardly facing annular shoulder 424 extends between first bore 420 and second bore 422. Below second bore 422, valve housing 416 defines a third bore 426 therein with an internally threaded surface 428 forming a port at the lower end of the valve housing.

Disposed in first bore 420 in valve housing 416 is a valve body 430 with an upwardly facing annular shoulder 432 thereon. An elastomeric valve seal 434 and a valve spacer 436, which provides support for the valve seal, are positioned adjacent to shoulder 432 on valve body 430. A conical valve head 438 is positioned above valve seal 434 and is attached to valve body 430 at threaded connection 440. It will be seen by those skilled in the art that valve seal 434 is adapted for sealing engagement with seat surface 414 in lower slip support 402 when valve body 430 is moved upwardly.

The lower end of valve body 430 is connected to a valve holder 442 by one or more pins 444. Valve holder 442 is disposed in second bore 422 of valve housing 416. A sealing means, such as O-ring 446 provides sealing engagement between valve holder 442 and valve housing 416.

Above shoulder 424 in valve housing 416, valve body 430 has a radially outwardly extending flange 448 thereon. A biasing means, such as spring 450, is disposed between flange 448 and shoulder 424 for biasing valve body 430 upwardly with respect to valve housing 416.

Valve holder 442 defines a first bore 452 and a smaller second bore 454 therein with an upwardly facing chamfered shoulder 456 extending therebetween. A ball 458 is disposed in valve holder 442 and is adapted for engagement with shoulder 456.

First Bridge Plug Embodiment

Referring now to FIG. 7, a first bridge plug embodiment of the present invention is shown and generally designated by the numeral 500. First bridge plug embodiment 500 comprises the same center mandrel 102 and the external components positioned thereon as does the second packer embodiment 100. Therefore, the reference numerals for these components shown in FIG. 7 are the same as in FIG. 3A.

The lower end of center mandrel 102 in first bridge plug embodiment 500 is connected to a lower slip support 502 at threaded connection 504. An upwardly and inwardly tapered shoulder 506 on lower slip support 502 engages shoulders 140 on lower slips 136. As with the other embodiments, slips 136 are adapted for sliding along shoulder 506.

Lower slip support 502 defines a bore 508 therein which is in communication with mandrel central opening 104 in center mandrel 102.

A bridging plug 510 is disposed in the upper portion of mandrel central opening 104 in center mandrel 102 and is sealingly engaged with internal seal 180. A radially outwardly extending flange 512 prevents bridging plug 510 from moving downwardly through center mandrel 102.

Above bridging plug 510 is tension sleeve 174, previously described for second packer embodiment 100.

Second Bridge Plug Embodiment

Referring now to FIG. 8, a second bridge plug embodiment of the present invention is shown and generally designated by the numeral 600. Second bridge plug embodiment 600 uses the same thin cross-sectional mandrel 202 as does third packer embodiment 200 shown in FIG. 4A. Also, the external components positioned on center mandrel 202 are the same as previously de-

scribed, so the same reference numerals are used in FIG. 8.

In second bridge plug embodiment 600, the lower end of center mandrel 202 is attached to the same lower slip support 502 as first bridge plug embodiment 500 at threaded connection 602. It will be seen that bore 508 in lower slip support 502 is in communication with mandrel central opening 204 in center mandrel 202.

A bridging plug 604 is positioned in the upper end of mandrel central opening 204 in center mandrel 202. A shoulder 608 in central opening 204 prevents downward movement of bridging plug 604. A sealing means, such as a plurality of O-rings 606, provide sealing engagement between bridging plug 604 and center mandrel 202.

Tension sleeve 238, previously described, is positioned above bridging plug 604.

Setting And Operation Of The Apparatus

Downhole tool apparatus 10 is positioned in well bore 12 and set into engagement therewith in a manner similar to prior art devices made with metallic components. For example, a prior art apparatus and setting thereof is disclosed in the above-referenced U.S. Pat. No. 4,151,875 to Sullaway. This patent is incorporated herein by reference.

For first packer embodiment 20, the setting tool pulls upwardly on tension sleeve 62, and thereby on mandrel 22, while holding lock ring housing 24. The lock ring housing is thus moved relatively downwardly along mandrel 22 which forces upper slips 28 outwardly and shears screws 36, pushing upper slip wedge 32 downwardly against packer elements 40 and 42. Screws 50 are also sheared and lower slip wedge 46 is pushed downwardly toward lower slip support 58 to force lower slips 54 outwardly. Eventually, upper slips 28 and lower slips 54 are placed in gripping engagement with well bore 12 and packer elements 40 and 42 are in sealing engagement with the well bore. The action of upper slips 28 and 54 prevent packer 20 from being unset. As will be seen by those skilled in the art, pressure below packer 20 cannot force the packer out of well bore 12, but instead, causes it to be even more tightly engaged.

Eventually, in the setting operation, tension sleeve 62 is sheared, so the setting tool may be removed from the well bore.

The setting of second packer embodiment 100, third packer embodiment 200, fourth packer embodiment 300, fifth packer embodiment 400, first bridge plug embodiment 500 and second bridge plug embodiment 600 is similar to that for first packer embodiment 20. The setting tool is attached to either tension sleeve 174 or 238. During setting, the setting tool pushes downwardly on upper slip support 110, thereby shearing shear pin 112. Upper slips 116 are moved downwardly with respect to upper slip wedge 126. Tapers 120 and upper slips 116 slide along upper slip wedge 126, and shoulders 118 on upper slips 116 slide along shoulder 114 on upper slip support 110. Thus, upper slips 116 are moved radially outwardly with respect to center mandrel 102 or 202 such that edges 124 of inserts 122 grippingly well bore 12.

Also during the setting operation, upper slip wedge 126 is forced downwardly, shearing shear pin 128. This in turn causes packer elements 40 and 42 to be squeezed outwardly into sealing engagement with the well bore.

The lifting on center mandrel 102 or 202 causes the lower slip support (valve housing 144 in first packer embodiment 100, valve housing 206 in second packer embodiment 200, valve housing 302 in fourth packer embodiment 300, lower slip support 402 in fifth packer embodiment 400, and lower slip support 502 in first bridge plug embodiment 500 and second bridge plug embodiment 600) to be moved up and lower slips 136 to be moved upwardly with respect to lower slip wedge 130. Tapers 134 in lower slips 136 slide along lower slip wedge 130, and shoulders 140 on lower slips 136 slide along the corresponding shoulder 142, 210, 306, 406, or 506. Thus, lower slips 136 are moved radially outwardly with respect to center mandrel 102 or 202 so that inserts 138 grippingly engage well bore 12.

Also during the setting operation, lower slip wedge 130 is forced upwardly, shearing shear pin 132, to provide additional squeezing force on packer elements 40 and 42.

The engagement of inserts 122 in upper slips 116 and inserts 138 in lower slips 136 with well bore 12 prevent packers 100, 200, 300, 400 and bridge plugs 500, 600 from coming unset.

Once any of packers 20, 100, 200, 300, 400 are set, the valves therein may be actuated in a manner known in the art. Sliding valve 164 in second packer embodiment 126, and sliding valve 22 in third packer embodiment 200 are set in a similar, if not identical manner. Sliding valve 318 in fourth packer embodiment 300 is also set in a similar manner, but does not utilize collets, nor is alignment of sliding valve 318 with respect to ports 316 in valve housing 302 important. Sliding valve 318 is simply moved below ports 316 to open the valve. Bumper seal 314 cushions the downward movement of sliding valve 318, thereby minimizing the possibility of damage to sliding valve 318 or valve housing 302 during an opening operation.

In fifth packer embodiment 400, the valve assembly comprising valve body 432, valve seal 434, valve spacer 436, valve head 438 and valve holder 442 is operated in a manner substantially identical to that of the Halliburton EZ Drill® squeeze packer of the prior art.

Drilling Out The Packer Apparatus

Drilling out any embodiment of downhole tool 10 may be carried out by using a standard drill bit at the end of tubing string 16. Cable tool drilling may also be used. With a standard "tri-cone" drill bit, the drilling operation is similar to that of the prior art except that variations in rotary speed and bit weight are not critical because the nonmetallic materials are considerably softer than prior art cast iron, thus making tool 10 much easier to drill out. This greatly simplifies the drilling operation and reduces the cost and time thereof.

In addition to standard tri-cone drill bits, and particularly if tool 10 is constructed utilizing engineering grade plastics for the mandrel as well as for slip wedges, slips, slip supports and housings, alternate types of drill bits may be used which would be impossible for tools constructed substantially of cast iron. For example, polycrystalline diamond compact (PDC) bits may be used. Drill bit 14 in FIG. 1 is illustrated as a PDC bit. Such drill bits have the advantage of having no moving parts which can jam up. Also, if the well bore itself was drilled with a PDC bit, it is not necessary to replace it with another or different type bit in order to drill out tool 10.

While specific squeeze packer and bridge plug configurations of packing apparatus 10 has been described herein, it will be understood by those skilled in the art

that other tools may also be constructed utilizing components selected of non-metallic materials, such as engineering grade plastics.

Additionally, components of the various packer embodiments may be interchanged. For example, thick cross-sectional center mandrel 102 may be used with valve housing 206 in second packer embodiment 200 or valve housing 302 in fourth packer embodiment 300. Similarly, thin cross-sectional center mandrel 202 could be used with valve body 144 in second packer embodiment 100 or lower slip support 402 and valve housing 416 in fifth packer embodiment 400. The intent of the invention is to provide devices of flexible design in which a variety of configurations may be used.

It will be seen, therefore, that the downhole tool packer apparatus and methods of drilling thereof of the present invention are well adapted to carry out the ends and advantages mentioned as well as those inherent therein. While presently preferred embodiments of the apparatus and various drilling methods have been discussed for the purposes of this disclosure, numerous changes in the arrangement and construction of parts and the steps of the methods may be made by those skilled in the art. In particular, the invention is not intended to be limited to squeeze packers or bridge plugs. All such changes are encompassed within the scope and spirit of the appended claims.

What is claimed is:

1. A well bore process comprising the steps of:
constructing a downhole tool such that a component thereof is made of a non-metallic material, said tool comprising:
a center mandrel; and
a plurality of slips disposed around said mandrel for grippingly engaging a well bore when in a set position;
wherein, at least one of said mandrel and said plurality of slips is said component;
positioning said downhole tool into locking, sealing engagement with said well bore; and
drilling said tool out of said well bore.

2. The process of claim 1 wherein said tool is selected from the group consisting of packers and bridge plugs.

3. The process of claim 1 wherein said component is subject to compressive loading.

4. The process of claim 1 wherein said component is subject to tensile loading.

5. The process of claim 1 wherein said center mandrel defines a central opening therein having a diameter less than about half an outside diameter of said center mandrel.

6. The process of claim 1 wherein said center mandrel defines a central opening therein having a diameter greater than about half the outside diameter of said center mandrel.

7. The process of claim 1 wherein said non-metallic material is plastic.

8. The process of claim 7 wherein said component is molded.

9. The process of claim 7 wherein said plastic is selected from the group consisting of nylon, phenolic material or epoxy resin.

10. The process of claim 9 wherein said plastic is a phenolic material and is selected from the group consisting of Fiberite FM4056J, Fiberite FM4005 or Resinoid 1360.

11. The process of claim 1 wherein said step of drilling is carried out with a polycrystalline diamond compact bit.

12. The process of claim 1 wherein said step of drilling is carried out using a drill bit without substantially varying weight applied to said drill bit.

13. A well bore process comprising the steps of:
positioning and setting a packing device into locked, sealing engagement with a well bore, a portion of said device being made of engineering grade plastic;
contacting said device with well fluids; and
drilling out said device using a polycrystalline diamond compact bit.

14. The process of claim 13 wherein said step of contacting is at a temperature of less than about 250° F.

15. The process of claim 13 wherein said step of contacting is at a pressure of less than about 5,000 psi.

16. The process of claim 13 wherein said portion of said device is at least one of a housing, slip, slip wedge, slip support, and mandrel thereof.

17. The process of claim 13 further comprising the step of, prior to said step of positioning and setting said device, drilling at least a portion of said well bore using a polycrystalline diamond compact bit.

18. The process of claim 13 wherein said step of drilling is carried out without substantially varying weight applied to said bit.

19. A downhole apparatus for use in a well bore, said apparatus comprising:
a center mandrel; and
slip means disposed on said mandrel for grippingly engaging said well bore when in a set position, said slip means comprising:
a slip wedge made of a non-metallic material; and
slips made of non-metallic material.

20. The apparatus of claim 19 characterized as a packing apparatus and further comprising packing means disposed on said mandrel for sealingly engaging said well bore when in a set position.

21. The apparatus of claim 20 wherein said slip means is an upper slip means disposed above said packing means and further comprising a lower slip means disposed below said packing means, said lower slip means comprising another slip wedge made of a non-metallic material.

22. The apparatus of claim 19 wherein said slip means comprises a slip support made of a non-metallic material.

23. The apparatus of claim 19 further comprising a plurality of hardened inserts molded into said material of said slips.

24. The apparatus of claim 19 wherein said non-metallic material is an engineering grade plastic.

25. The apparatus of claim 24 wherein said plastic is nylon.

26. The apparatus of claim 24 wherein said plastic is a phenolic material.

27. The apparatus of claim 26 wherein said phenolic material is one of Fiberite FM4056J, Fiberite FM4005 and Resinoid 1360.

28. The apparatus of claim 24 wherein said plastic is an epoxy resin.

29. The apparatus of claim 24, wherein said wedge is molded to size.

30. A downhole apparatus for use in a well bore, said apparatus comprising:
a center mandrel made of a non-metallic material; and

slip means disposed on said mandrel for grippingly engaging said well bore when in a set position.

31. The apparatus of claim 30 characterized as a packing apparatus and further comprising packing means disposed on said mandrel for sealingly engaging said well bore when in a set position.

32. The apparatus of claim 30 wherein said slip means comprises a wedge made of a non-metallic material.

33. The apparatus of claim 30 wherein said slip means comprises slips made of a non-metallic material.

34. The apparatus of claim 30 wherein said non-metallic material is an engineering grade plastic.

35. The apparatus of claim 34 wherein said plastic is nylon.

36. The apparatus of claim 34 wherein said plastic is a phenolic material.

37. The apparatus of claim 36 wherein said phenolic material is Fiberite FM4056J.

38. The apparatus of claim 34 wherein said mandrel is molded to size.

39. The apparatus of claim 34 wherein said mandrel has a central opening defined therethrough having a diameter less than about half an outside diameter of said mandrel.

40. The apparatus of claim 34 wherein said mandrel has a central opening defined therethrough having a diameter greater than about half an outside diameter of said mandrel.

41. The apparatus of claim 34 wherein said plastic is an epoxy resin.

42. A downhole apparatus for use in a well bore, said apparatus comprising:

a center mandrel; and

a plurality of slips disposed around said mandrel for grippingly engaging said well bore when in a set position, said slips being made of a non-metallic material.

43. The apparatus of claim 42 characterized as a packing apparatus and further comprising packing means disposed on said mandrel for sealingly engaging said well bore when in a set position; and

wherein some of said slips are disposed above said packing means and some of said slips are disposed below said packing means.

44. The apparatus of claim 42 further comprising a wedge disposed adjacent to said slips, said wedge being made of a non-metallic material.

45. The apparatus of claim 42 wherein said mandrel is made of a non-metallic material.

46. The apparatus of claim 42 wherein said non-metallic material is an engineering grade plastic.

47. The apparatus of claim 46 wherein said plastic material is nylon.

48. The apparatus of claim 46 wherein said plastic is a phenolic material.

49. The apparatus of claim 48 wherein said phenolic material is Fiberite FM4056J.

50. The apparatus of claim 46 wherein said plastic is an epoxy resin.

51. The apparatus of claim 46 wherein said slips are molded of said plastic material.

52. The apparatus of claim 51 further comprising a plurality of hardened inserts molded into said plastic.

53. The apparatus of claim 52 wherein each of said inserts has an edge adapted for grippingly engaging said well bore.

54. A packing apparatus for use in a well bore, said apparatus comprising:

a mandrel made of a non-metallic material;

an upper slip support disposed on said mandrel and made of a non-metallic material;

a plurality of upper slips disposed around said mandrel and substantially made of a non-metallic material;

packing means disposed on said mandrel below said upper slips for sealingly engaging said well bore when in a set position;

a plurality of lower slips disposed around said mandrel below said packing means and substantially made of a non-metallic material; and

a lower slip support attached to said mandrel and made of a non-metallic material.

55. The apparatus of claim 54 wherein said non-metallic material of any of said mandrel, upper slip support, upper slips, lower slips and lower slip support is an engineering grade plastic.

56. The apparatus of claim 55 wherein said plastic is nylon.

57. The apparatus of claim 56 wherein said phenolic material is one of Fiberite FM4056J, Fiberite FM4005 and Resinoid 1360.

58. The apparatus of claim 55 wherein said plastic is a phenolic material.

59. The apparatus of claim 55 wherein said plastic is an epoxy resin.

60. The apparatus of claim 55 wherein any of said mandrel, upper slip support upper slips, lower slips and lower slip support may be molded to size.

61. The apparatus of claim 59 wherein:

said center mandrel defines a mandrel central opening therethrough;

said lower slip support is characterized by a valve housing defining a housing central opening therein and a housing port in communication with said housing central opening; and

further comprising a valve disposed in said housing central opening and providing communication between said port and said mandrel central opening when in an open position, said valve being disposed below a lower end of said mandrel.

62. The apparatus of claim 61 wherein upward movement of said valve is prevented by said mandrel.

63. The apparatus of claim 61 wherein said valve is a sliding valve defining a valve central opening therein and a valve port in communication with said valve central opening, wherein said valve port and said housing port are substantially aligned when said valve is in an open position.

64. The apparatus of claim 63 wherein said valve defines a seal groove therein; and

further comprising sealing means disposed in said seal groove for providing sealing engagement between said valve and said valve housing.

65. The apparatus of claim 63 wherein said valve housing defines a seal groove therein; and

further comprising sealing means disposed in said seal groove for providing sealing engagement between said valve and said valve housing.

66. The apparatus of claim 63 further comprising a bumper seal disposed below said valve for cushioning said valve as said valve is moved to said open position thereof.

67. The apparatus of claim 63 further comprising means for preventing relative rotation between said sliding valve and said valve housing.

68. The apparatus of claim 61 wherein said valve is positioned below said housing port when said valve is in said open position.

69. The apparatus of claim 61 further comprising a poppet type valve disposed in said valve housing for providing communication between said mandrel central opening and said housing port when said valve is in an open position.

70. The apparatus of claim 54 further comprising a bridging plug disposed in said mandrel and sealingly engaged therewith.

71. The apparatus of claim 58 wherein:

said upper slip support has a tapered shoulder on a lower end thereof;

said upper slips have a tapered shoulder on an upper end thereof adapted for sliding engagement with said shoulder on said upper slip support;

said lower slip support has a tapered shoulder on an upper end thereof; and

said lower slips have a tapered shoulder on a lower end thereof adapted for sliding engagement with said shoulder on said lower slip support.

72. The apparatus of claim 54 further comprising a plurality of inserts molded into each of said upper and lower slips, said inserts being made of a hardened material adapted for grippingly engaging said well bore.

73. A downhole apparatus for use in a well bore, said apparatus comprising:

a center mandrel made of a non-metallic material; and

slip means disposed on said mandrel for grippingly engaging said well bore when in a set position, said slip means comprising a slip wedge made of a non-metallic material.

74. A downhole apparatus for use in a well bore, said apparatus comprising a slip adapted for grippingly engaging the well bore, said slip being made of a non-metallic, non-elastomeric material.

75. A downhole apparatus for use in a well bore, said apparatus comprising:

a slip adapted for grippingly engaging the well bore, said slip being made of a non-metallic material; and

a hardened insert molded into said slip.

* * * * *

The United States of America

The Commissioner of Patents and Trademarks

Has received an application for a patent for a new and useful invention. The title and description of the invention are enclosed. The requirements of law have been complied with, and it has been determined that a patent on the invention shall be granted under the law.

Therefore, this

United States Patent

Grants to the person or persons having title to this patent the right to exclude others from making, using or selling the invention throughout the United States of America for the term of seventeen years from the date of this patent, subject to the payment of maintenance fees as provided by law.

Michael K. Kirk

Acting Commissioner of Patents and Trademarks

Sandra J. Morton

Attest

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US005224540A

United States Patent [19]

Streich et al.

[11] Patent Number: 5,224,540

[45] Date of Patent: Jul. 6, 1993

[54] DOWNHOLE TOOL APPARATUS WITH NON-METALLIC COMPONENTS AND METHODS OF DRILLING THEREOF

[75] Inventors: Steven G. Streich; Donald F. Hushbeck; Kevin T. Berscheidt; Rick D. Jacobi, all of Duncan, Okla.

[73] Assignee: Halliburton Company, Duncan, Okla.

[21] Appl. No.: 883,619

[22] Filed: May 12, 1992

Related U.S. Application Data

[63] Continuation-in-part of Ser. No. 719,740, Jun. 21, 1991, which is a continuation-in-part of Ser. No. 515,019, Apr. 26, 1990, abandoned.

[51] Int. Cl.[5] E21B 33/129

[52] U.S. Cl. 166/118; 166/123; 166/128; 166/134; 166/382

[58] Field of Search 166/387, 376, 118, 135, 166/138, 179, 192

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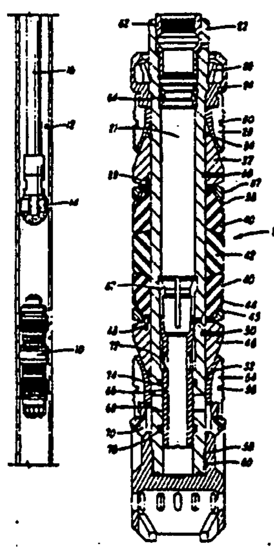
Primary Examiner—Stephen J. Novosad
Attorney, Agent, or Firm—James R. Duzah; Neal R. Kennedy

[57] ABSTRACT

A downhole tool apparatus and methods of drilling the apparatus. The apparatus may include, but is not limited to, packers and bridge plugs utilizing non-metallic slip components. The non-metallic material may include engineering grade plastics. In one embodiment, the slips are separate and held in place in an initial position around the slip wedge by a retainer ring. In another embodiment, the slips are integrally formed with a ring portion which holds the slips in the initial position around the wedge; in this embodiment, the ring portion is made of a fracturable non-metallic material which fractures during a setting operation to separate the slips. Methods of drilling out the apparatus without significant variations in the drilling speed and weight applied to the drill bit may be employed. Alternative drill bit types, such as polycrystalline diamond compact (PDC) bits may also be used.

41 Claims, 7 Drawing Sheets



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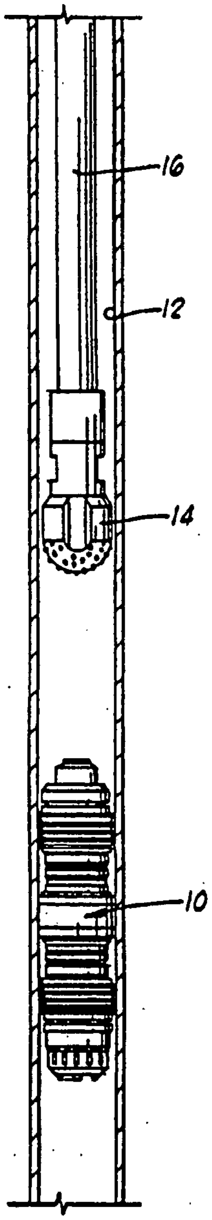
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FIG. 1

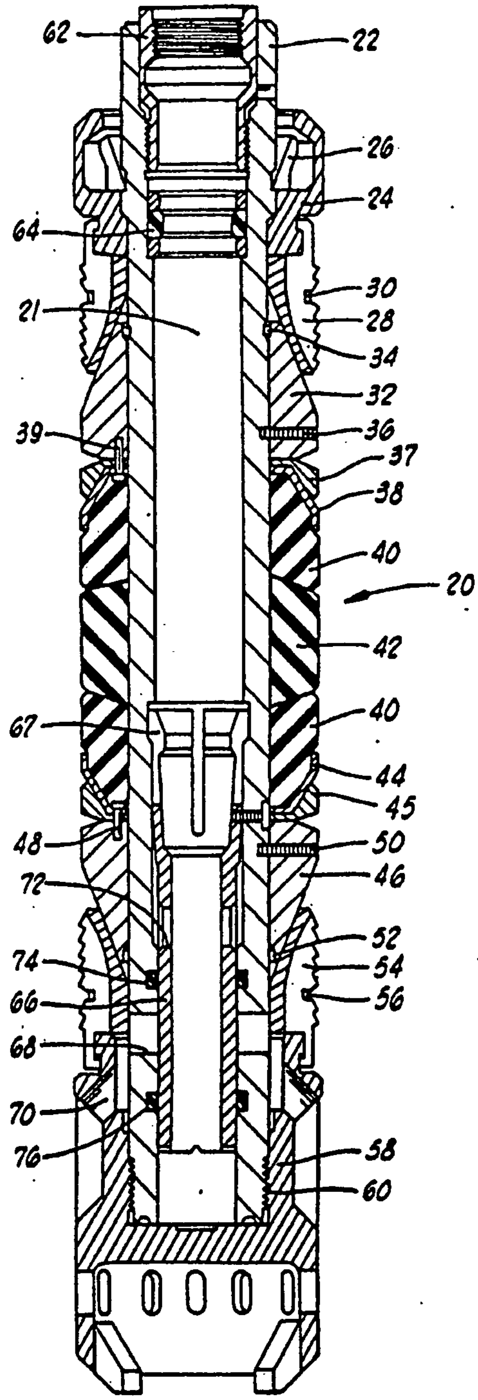
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FIG. 2

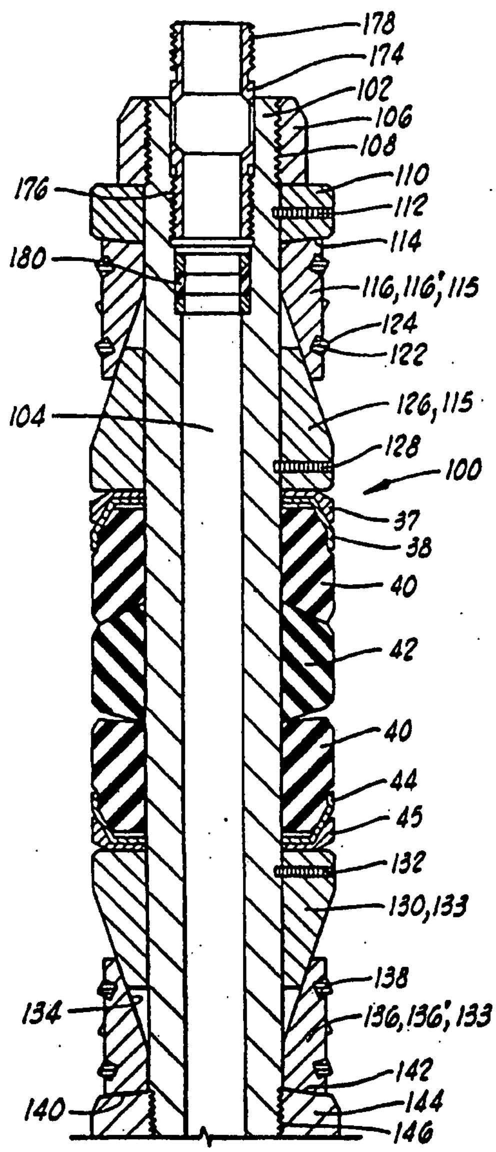
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FIG. 3A

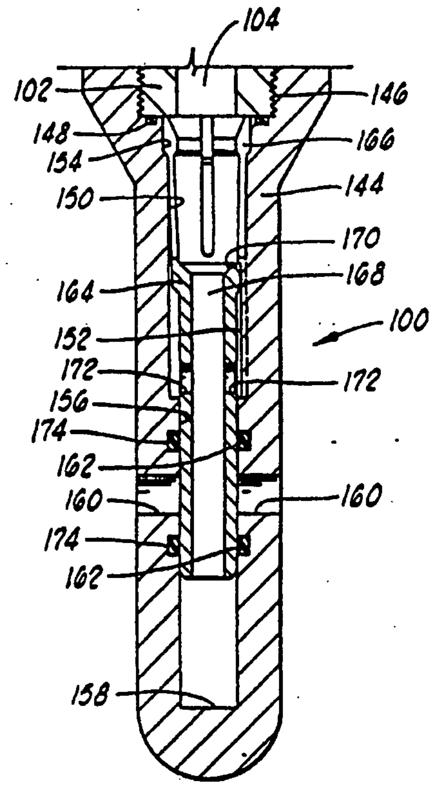
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FIG. 3B

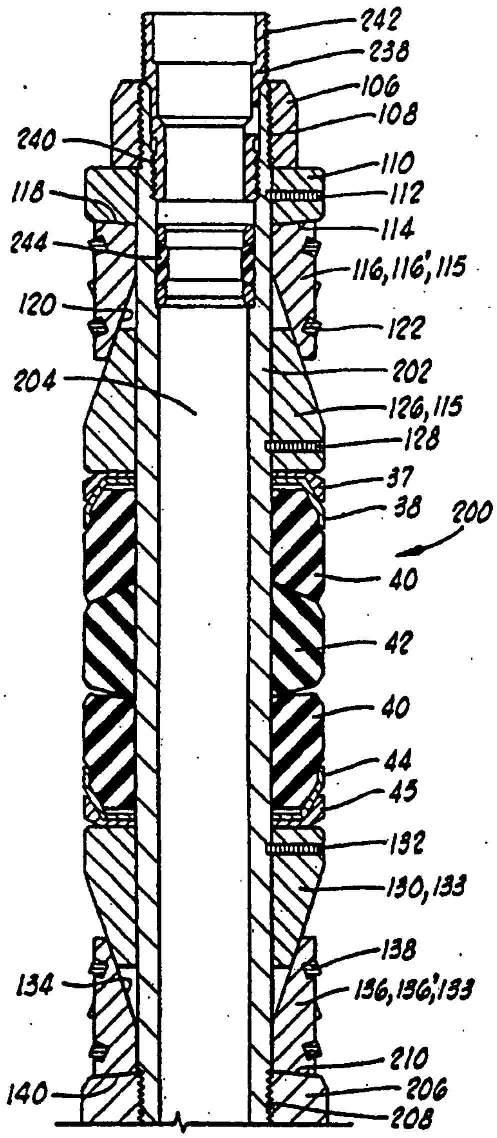
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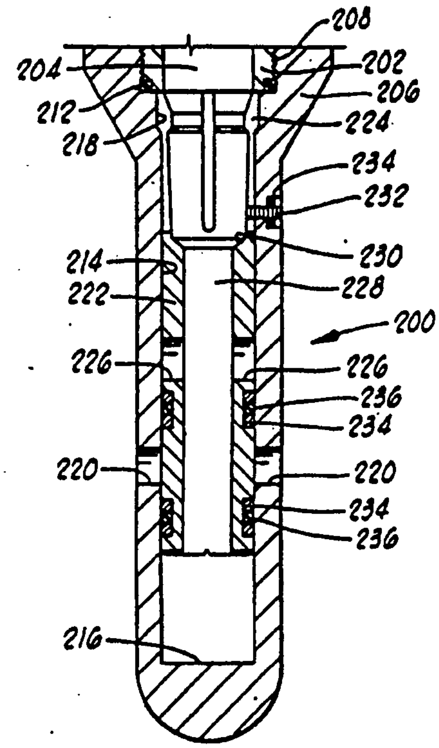
FIG. 4A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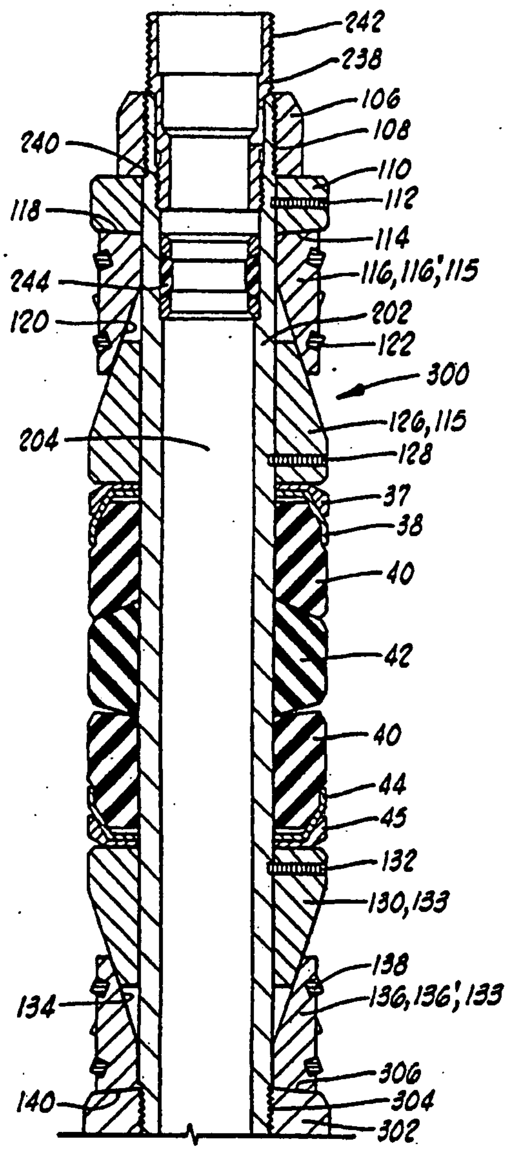
216

FIG. 4B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238
106
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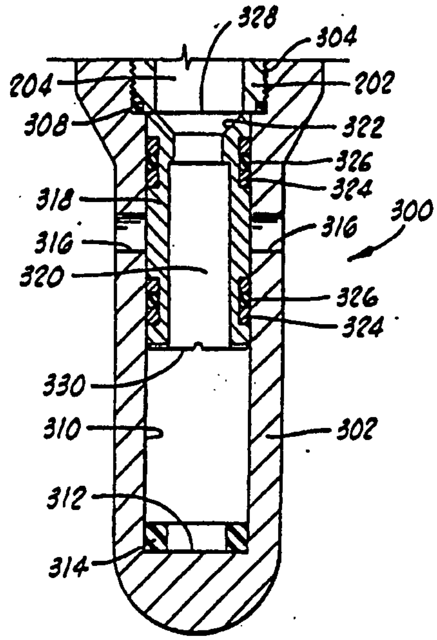
110
112
118
114
244
116,116',115
202
120
122
300
204
126,115
128
37
38
40
42
40
44
45
132
130,133
138
134
136,136',133
306
140
304
302

FIG. 5A


328
304
204
202
308
322
326
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318
316
300
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320
326
324
330
310
302
312
314

FIG. 5B

40960.07170006

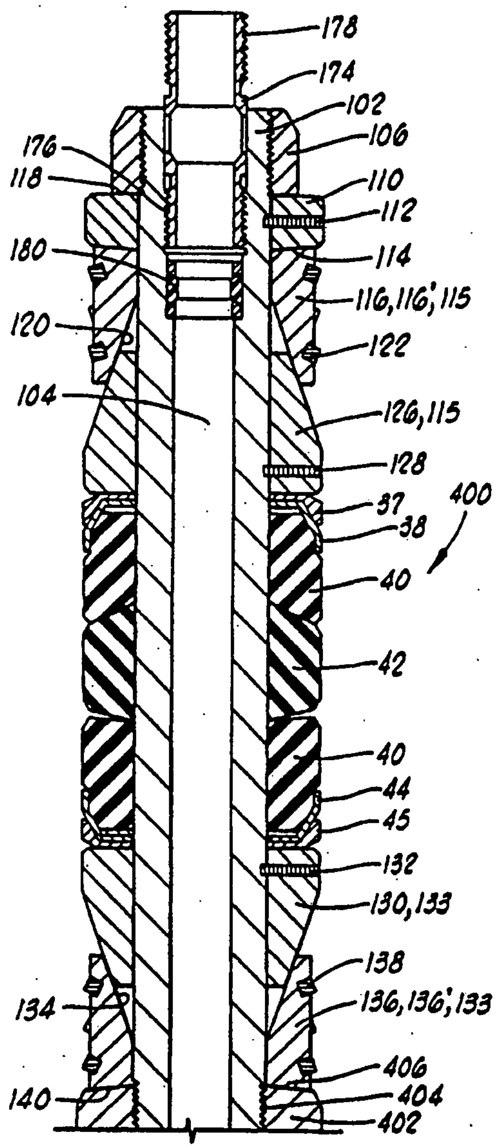


FIG. 6A

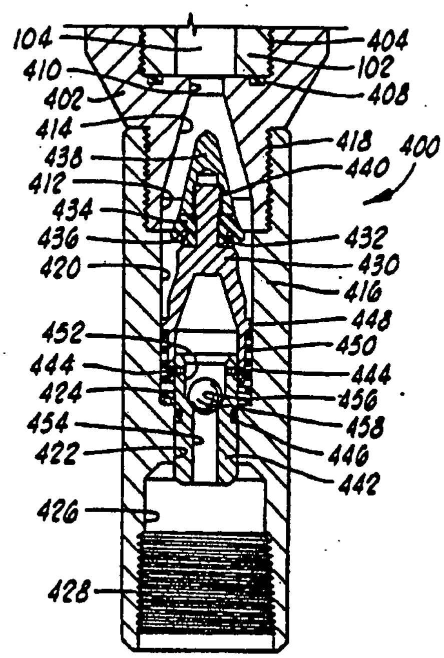


FIG. 6B

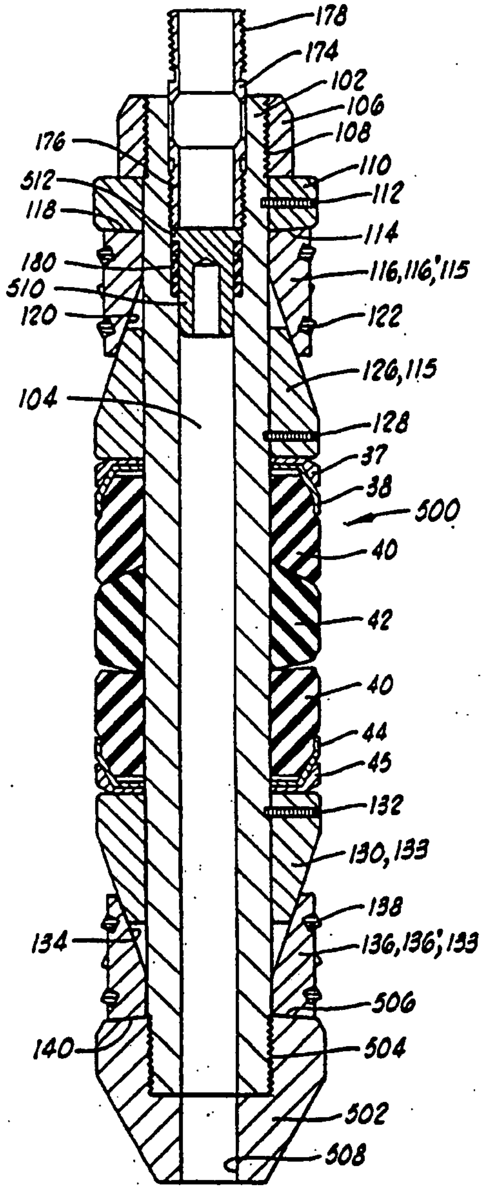
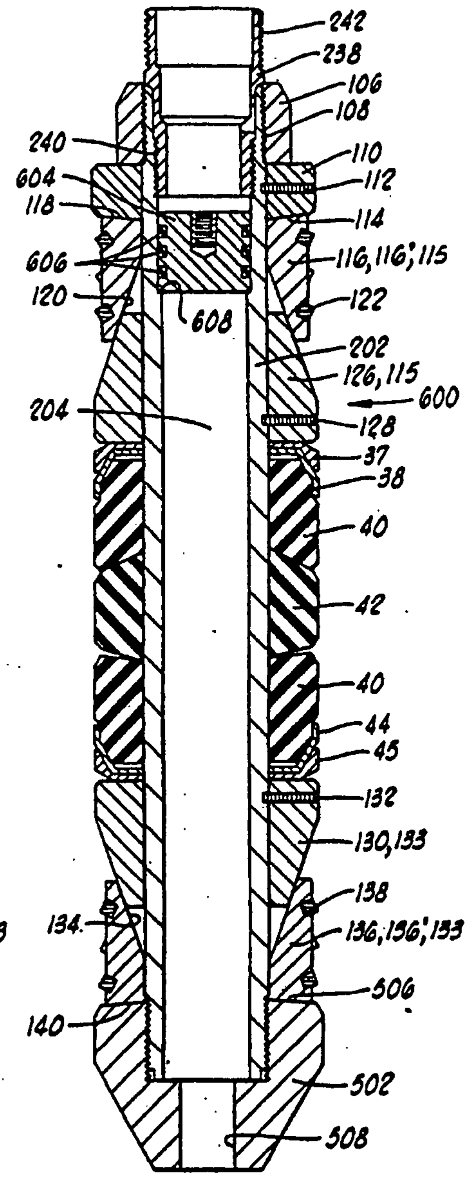

178
174
102
106
108
110
112
114
116,116',115
122
126,115
128
37
38
500
40
42
40
44
45
132
130,133
138
136,136',133
506
504
502
508
176
512
118
180
510
120
104
134
140

FIG. 7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238
106
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110
112
114
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122
202
126,115
600
128
37
38
40
42
40
44
45
132
130,133
138
136,136',133
506
502
508
240
604
118
606
120
608
204
134
140

FIG. 8

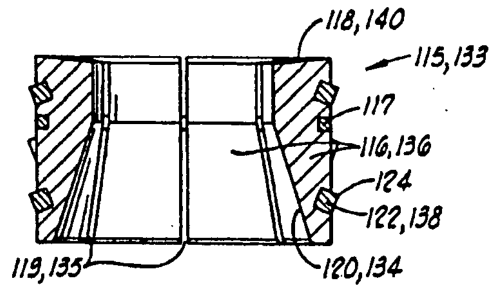

FIG. 9

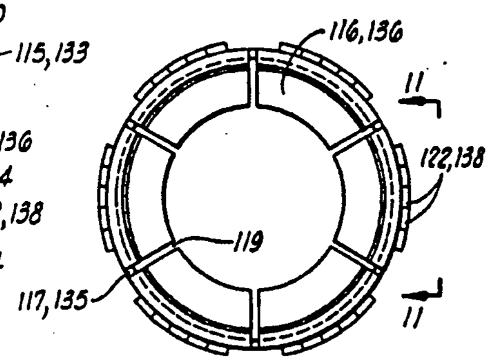

FIG. 10

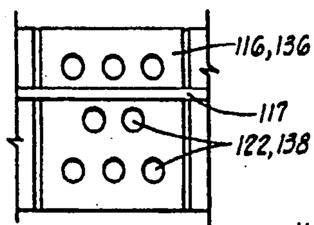

FIG. 11

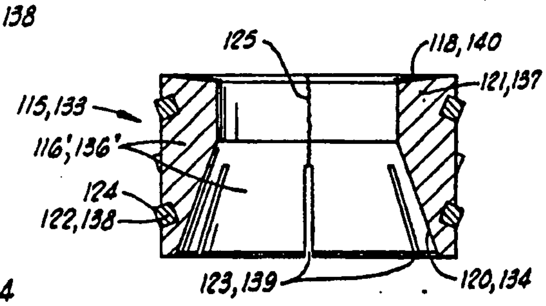

FIG. 12

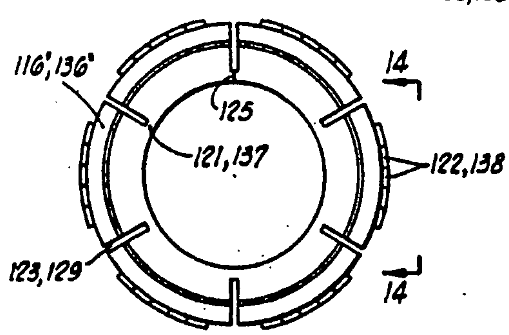

FIG. 13

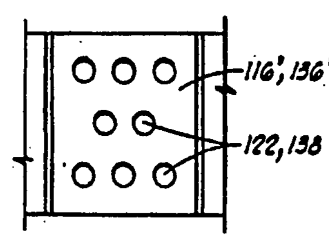

FIG. 14

DOWNHOLE TOOL APPARATUS WITH NON-METALLIC COMPONENTS AND METHODS OF DRILLING THEREOF

This application is a continuation-in-part of co-pending application Ser. No. 07/719,740, filed Jun. 21, 1991, which was a continuation-in-part of application Ser. No. 07/515,019, filed Apr. 26, 1990 and now abandoned.

BACKGROUND OF THE INVENTION

1. Field Of The Invention

This invention relates to downhole tools for use in well bores and methods of drilling such apparatus out of well bores, and more particularly, to such tools having drillable components, such as slips, therein made at least partially of non-metallic materials, such as engineering grade plastics.

2. Description Of The Prior Art

In the drilling or reworking of oil wells, a great variety of downhole tools are used. For example, but not by way of limitation, it is often desirable to seal tubing or other pipe in the casing of the well, such as when it is desired to pump cement or other slurry down tubing and force the slurry out into a formation. It then becomes necessary to seal the tubing with respect to the well casing and to prevent the fluid pressure of the slurry from lifting the tubing ou of the well. Packers and bridge plugs designed for these general purposes are well known in the art.

When it is desired to remove many of these downhole tools from a well bore, it is frequently simpler and less expensive to mill or drill them out rather than to implement a complex retrieving operation. In milling, a milling cutter is used to grind the packer or plug, for example, or at least the outer components thereof, out of the well bore. Milling is a relatively slow process, but it can be used on packers or bridge plugs having relatively hard components such as erosion-resistant hard steel. One such packer is disclosed in U.S. Pat. No. 4,151,875 to Sullaway, assigned to the assignee of the present invention and sold under the trademark EZ Disposal packer. Other downhole tools in addition to packers and bridge plugs may also be drilled out.

In drilling, a drill bit is used to cut and grind up the components of the downhole tool to remove it from the well bore. This is a much faster operation than milling, but requires the tool to be made out of materials which can be accommodated by the drill bit. Typically, soft and medium hardness cast iron are used on the pressure bearing components, along with some brass and aluminum items. Packers of this type include the Halliburton EZ Drill ® and EZ Drill SV ® squeeze packers.

The EZ Drill SV ® squeeze packer, for example, includes a lock ring housing, upper slip wedge, lower slip wedge, and lower slip support made of soft cast iron. These components are mounted on a mandrel made of medium hardness cast iron. The EZ Drill ® squeeze packer is similarly constructed. The Halliburton EZ Drill ® bridge plug is also similar, except that it does not provide for fluid flow therethrough.

All of the above-mentioned packers are disclosed in Halliburton Services Sales and Service Catalog No. 43, pages 2561–2562, and the bridge plug is disclosed in the same catalog on pages 2556–2557.

The EZ Drill ® packer and bridge plug and the EZ Drill SV ® packer are designed for fast removal from the well bore by either rotary or cable tool drilling methods. Many of the components in these drillable packing devices are locked together to prevent their spinning while being drilled, and the harder slips are grooved so that they will be broken up in small pieces. Typically, standard "tri-cone" rotary drill bits are used which are rotated at speeds of about 75 to about 120 rpm. A load of about 5,000 to about 7,000 pounds of weight is applied to the bit for initial drilling and increased as necessary to drill out the remainder of the packer or bridge plug, depending upon its size. Drill collars may be used as required for weight and bit stabilization.

Such drillable devices have worked well and provide improved operating performance at relatively high temperature and pressures. The packers and plug mentioned above are designed to withstand pressures of about 10,000 psi and temperatures of about 425° F. after being set in the well bore. Such pressures and temperatures require the cast iron components previously discussed.

However, drilling out iron components requires certain techniques. Ideally, the operator employs variations in rotary speed and bit weight to help break up the metal parts and reestablish bit penetration should bit penetration cease while drilling. A phenomenon known as "bit tracking" can occur, wherein the drill bit stays on one path and no longer cuts into the downhole tool. When this happens, it is necessary to pick up the bit above the drilling surface and rapidly recontact the bit with the packer or plug and apply weight while continuing rotation. This aids in breaking up the established bit pattern and helps to reestablish bit penetration. If this procedure is used, there are rarely problems. However, operators may not apply these techniques or even recognize when bit tracking has occurred. The result is that drilling times are greatly increased because the bit merely wears against the surface of the downhole tool rather than cutting into it to break it up.

While cast iron components may be necessary for the high pressures and temperatures for which they are designed, it has been determined that many wells experience pressures less than 10,000 psi and temperatures less than 425° F. This includes most wells cemented. In fact, in the majority of wells, the pressure is less than about 5,000 psi, and the temperature is less than about 250° F. Thus, the heavy duty metal construction of the previous downhole tools, such as the packers and bridge plugs described above, is not necessary for many applications, and if cast iron components can be eliminated or minimized the potential drilling problems resulting from bit tracking might be avoided as well.

The downhole tool of the present invention solves this problem by providing an apparatus wherein at least some of the components, including slips and pressure bearing components, are made at least partially of non-metallic materials, such as engineering grade plastics. Such plastic components are much more easily drilled than cast iron, and new drilling methods may be employed which use alternative drill bits such as polycrystalline diamond compact bits, or the like, rather than standard tri-cone bits.

SUMMARY OF THE INVENTION

The downhole tool apparatus of the present invention utilizes non-metallic materials, such as engineering grade plastics, to reduce weight, to reduce manufacturing time and labor, to improve performance through

reducing frictional forces of sliding surfaces, to reduce costs and to improve drillability of the apparatus when drilling is required to remove the apparatus from the well bore. Primarily, in this disclosure, the downhole tool is characterized by well bore packing apparatus, but it is not intended that the invention be limited to such packing devices. The non-metallic components in the downhole tool apparatus also allow the use of alternative drilling techniques to those previously known.

In packing apparatus embodiments of the present invention, the apparatus may utilize the same general geometric configuration of previously known drillable packers and bridge plugs while replacing at least some of the metal components with non-metallic materials which can still withstand the pressures and temperatures exposed thereto in many well bore applications. In other embodiments of the present invention, the apparatus may comprise specific design changes to accommodate the advantages of plastic materials and also to allow for the reduced strengths thereof compared to metal components.

In one embodiment of the downhole tool, the invention comprises a center mandrel and slip means disposed on the mandrel for grippingly engaging the well bore when in a set position. In packing embodiments, the apparatus further comprises a packing means disposed on the mandrel for sealingly engaging the well bore when in a set position.

The slips means comprises a slip wedge positioned around the center mandrel, a plurality of slips disposed in an initial position around the mandrel and adjacent to the wedge, retaining means for holding the slips in the initial position, and a slip support on an opposite side of the slips from the wedge. In one embodiment, the slips are separate and the retaining means is characterized by a retaining band extending at least partially around the slips. In another embodiment, the retaining means is characterized by a ring portion integrally formed with the slips. This ring portion is fracturable during a setting operation. whereby the slips are separated so that they can be moved into gripping engagement with the well bore. Hardened inserts may be molded into the slips of either embodiment. The inserts may be metallic, such as hardened steel, or non-metallic, such as ceramic.

Any of the mandrel, slips, slip wedges or slip supports may be made of the non-metallic material, such as plastic. Specific plastics include nylon, phenolic materials and epoxy resins. The phenolic materials may further include any of Fiberite FM4056J, Fiberite FM4005 or Resinoid 1360. The plastic components may be molded or machined.

One preferred plastic material for at least some of these components is a glass reinforced phenolic resin having a tensile strength of about 18,000 psi and a compressive strength of about 40,000 psi, although the invention is not intended to be limited to this particular plastic or a plastic having these specific physical properties. The plastic materials are preferably selected such that the packing apparatus can withstand well pressures less than about 10,000 psi and temperatures less than about 425° F. In one preferred embodiment, but not by way of limitation, the plastic materials of the packing apparatus are selected such that the apparatus can withstand well pressures up to about 5,000 psi and temperatures up to about 250° F.

Most of the components of the slip means are subjected to substantially compressive loading when in a sealed operating position in the well bore, although some tensile loading may also be experienced. The center mandrel typically ha tensile loading applied thereto when setting the packer and when the packer is in its operating position.

One new method of the invention is a well bore process comprising the steps of positioning a downhole tool into engagement with the well bore; prior to the step of positioning, constructing the tool such that a component thereof is made of a non-metallic material; and then drilling the tool out of the well bore. The tool may be selected from the group consisting packers and bridge plugs, but is not limited to these devices.

The component made of non-metallic material, may be one of several such components. The components may be substantially subject to compressive loading. Such components in the tool may include lock ring housings, slips, slip wedges and slip supports. Some components, such as center mandrels of such tools may be substantially subjected to tensile loading.

In another embodiment, the step of drilling is carried out using a polycrystalline diamond compact bit. Regardless of the type of drill bit used, the process may further comprise the step of drilling using a drill bit without substantially varying the weight applied to the drill bit.

In another method of the invention, a well bore process comprises the steps of positioning and setting a packing device in the well bore, a portion of the device being made of engineering grade plastic; contacting the device with well fluids; and drilling out the device using a drill bit having no moving parts such as a polycrystalline diamond compact bit. This or a similar drill bit might have been previously used in drilling the well bore itself, so the process may be said to further comprise the step of, prior to the step of positioning and setting the packer, drilling at least a portion of the well bore using a drill bit such as a polycrystalline diamond compact bit.

In one preferred embodiment, the step of contacting the packer is at a pressure of less than about 5,000 psi and a temperature of less than about 250° F, although higher pressures and temperatures may also be encountered.

It is an important object of the invention to provide a downhole tool apparatus utilizing components, such as slip means, made at least partially of non-metallic materials and methods of drilling thereof.

It is another object of the invention to provide a well bore packing apparatus using slip means components made of engineering grade plastic.

It is a further object of the invention to provide a packing apparatus which may be drilled by alternate methods to those using standard rotary drill bits.

Additional objects and advantages of the invention will become apparent as the following detailed description of the preferred embodiments is read in conjunction with the drawings which illustrate such preferred embodiments.

BRIEF DESCRIPTION OF THE DRAWINGS

FIG. 1 generally illustrates the downhole tool of the present invention positioned in a well bore with a drill bit disposed thereabove.

FIG. 2 illustrates a cross section of one embodiment of a drillable packer made in accordance with the invention.

FIGS. 3A and 3B show a cross section of a second embodiment of a drillable packer.

FIGS. 4A and 4B show a third drillable packer embodiment.

FIGS. 5A and 5B illustrate a fourth embodiment of a drillable packer.

FIGS. 6A and 6B show a fifth drillable packer embodiment with a poppet valve therein.

FIG. 7 shows a cross section of one embodiment of a drillable bridge plug made in accordance with the present invention.

FIG. 8 illustrates a second embodiment of a drillable bridge plug.

FIG. 9 is a vertical cross section of one preferred embodiment of slips used in the drillable packer and bridge plug of the plug of the present invention.

FIG. 10 is an end view of the slips shown in FIG. 9.

FIG. 11 is an elevational view taken along lines 11—11 in FIG. 10.

FIG. 12 shows a vertical cross section of an alternate embodiment of slips used in the drillable packer and bridge plug of the present invention.

FIG. 13 is an end view of the slips of FIG. 12.

FIG. 14 shows an elevation as seen along lines 14—14 in FIG. 13.

DESCRIPTION OF THE PREFERRED EMBODIMENT

Referring now to the drawings, and more particularly to FIG. 1, the downhole tool apparatus of the present invention is shown and generally designated by the numeral 10. Apparatus 10, which may include, but is not limited to, packers, bridge plugs, or similar devices, is shown in an operating position in a well bore 12. Apparatus 10 can be set in this position by any manner known in the art such as setting on a tubing string or wire line. A drill bit 14 connected to the end of a tool or tubing string 16 is shown above apparatus 10 in a position to commence the drilling out of apparatus 10 from well bore 12. Methods of drilling will be further discussed herein.

First Packer Embodiment

Referring now to FIG. 2, the details of a first squeeze packer embodiment 20 of apparatus 10 will be described. The size and configuration of packer 20 is substantially the same as the previously mentioned prior art EZ Drill SV® squeeze packer. Packer 20 defines a generally central opening 21 therein.

Packer 20 comprises a center mandrel 22 on which most of the other components are mounted. A lock ring housing 24 is disposed around an upper end of mandrel 22 and generally encloses a lock ring 26.

Disposed below lock ring housing 24 and pivotally connected thereto are a plurality of upper slips 28 initially held in place by a retaining means, such as retaining band or ring 30. A generally conical upper slip wedge is disposed around mandrel 22 adjacent to upper slips 30. Upper slip wedge 32 is held in place on mandrel 22 by a wedge retaining ring 34 and a plurality of screws 36.

Adjacent to the lower end of upper slip wedge 32 is an upper back-up ring 37 and an upper packer shoe 38 connected to the upper slip wedge by a pin 39. Below upper packer shoe 38 are a pair of end packer elements 40 separated by center packer element 42. A lower packer shoe 44 and lower back-up ring 45 are disposed adjacent to the lowermost end packer element 40.

A generally conical lower slip wedge 46 is positioned around mandrel 22 adjacent to lower packer shoe 44, and a pin 48 connects the lower packer shoe to the lower slip wedge.

Lower slip wedge 46 is initially attached to mandrel 22 by a plurality of screws 50 and a wedge retaining ring 52 in a manner similar to that for upper slip wedge 32. A plurality of lower slips 54 are disposed adjacent to lower slip wedge 46 and are initially held in place by a retaining means, such as retaining band or ring 56. Lower slips 54 are pivotally connected to the upper end of a lower slip support 58. Mandrel 22 is attached to lower slip support 58 at threaded connection 60.

Disposed in mandrel 22 at the upper end thereof is a tension sleeve 62 below which is an internal seal 64. Tension sleeve 62 is adapted for connection with a setting tool (not shown) of a kind known in the art.

A collet-latch sliding valve 66 is slidably disposed in central opening 21 at the lower end of mandrel 22 adjacent to fluid ports 68 in the mandrel. Fluid ports 68 in mandrel 22 are in communication with fluid ports 70 in lower slip housing 58. The lower end of lower slip support 58 is closed below ports 70.

Sliding valve 66 defines a plurality of valve ports 72 which can be aligned with fluid ports 68 in mandrel 22 when sliding valve 66 is in an open position. Thus, fluid can flow through central opening 21.

On the upper end of sliding valve 66 are a plurality of collet fingers 67 which are adapted for latching and unlatching with a valve actuation tool (not shown) of a kind known in the art. This actuation tool is used to open and close sliding valve 66 as further discussed herein. As illustrated in FIG. 2, sliding valve 66 is in a closed position wherein fluid ports 68 are sealed by upper and lower valve seals 74 and 76.

In prior art drillable packers and bridge plugs of this type, mandrel 22 is made of a medium hardness cast iron, and lock ring housing 24, upper slip wedge 32, lower slip wedge 46 and lower slip support 58 are made of soft cast iron for drillability. Most of the other components are made of aluminum, brass or rubber which, of course, are relatively easy to drill. Prior art upper and lower slips 28 and 54 are made of hard cast iron, but are grooved so that they will easily be broken up in small pieces when contacted by the drill bit during a drilling operation.

As previously described, the soft cast iron construction of prior art lock ring housings, upper and lower slip wedges, and lower slip supports are adapted for relatively high pressure and temperature conditions, while a majority of well applications do not require a design for such conditions. Thus, the apparatus of the present invention, which is generally designed for pressures lower than 10,000 psi and temperatures lower than 425° F., utilizes engineering grade plastics for at least some of the components. For example, the apparatus may be designed for pressures up to about 5,000 psi and temperatures up to about 250° F., although the invention is not intended to be limited to these particular conditions.

In first packer embodiment 20, at least some of the previously soft cast iron components of the slip means, such as lock ring housing 24, upper and lower slip wedges 32 and 46 and lower slip support 58 are made of engineering grade plastics. In particular, upper and lower slip wedges 32 and 46 are subjected to substantially compressive loading. Since engineering grade plastics exhibit good strength in compression, they make excellent choices for use in components subjected to compressive loading. Lower slip support 58 is also subjected to substantially compressive loading and can

be made of engineering grade plastic when packer 20 is subjected to relative low pressures and temperatures.

Lock ring housing 24 is mostly in compression, but does exhibit some tensile loading. However, in most situations, this tensile loading is minimal, and lock ring housing 24 may also be made of an engineering grade plastic of substantially the same type as upper and lower slip wedges 32 and 46 and also lower slip housing 58.

Upper and lower slips 28 and 54 are illustrated in FIG. 2 as having a conventional configuration. However, non-metallic materials may be used, and thus upper and lower slips 28 and 54 may be made of plastic, for example, in some applications. Hardened inserts for gripping well bore 12 when packer 20 is set may be required as part of the plastic slips. New embodiments of slips utilizing such non-metallic materials will be described later herein.

Lock ring housing 24, upper slip wedge 32, lower slip wedge 46, and lower slip housing 58 comprise approximately 75% of the cast iron of the prior art squeeze packers. Thus, replacing these components with similar components made of engineering grade plastics will enhance the drillability of packer 20 and reduce the time and cost required therefor.

Mandrel 22 is subjected to tensile loading during setting and operation, and many plastics will not be acceptable materials therefor. However, some engineering plastics exhibit good tensile loading characteristics, so that construction of mandrel 22 from such plastics is possible. Reinforcements may be provided in the plastic resin as necessary.

Example

A first embodiment packer 20 was constructed in which upper slip wedge 32 and lower slip wedge 46 were constructed by molding the parts to size from a phenolic resin plastic with glass reinforcement. The specific material used was Fiberite 4056J manufactured by Fiberite Corporation of Winona, Minn. This material is classified by the manufacturer as a two stage phenolic with glass reinforcement. It has a tensile strength of 18,000 psi and a compressive strength of 40,000 psi.

The test packer 20 held to 8,500 psi without failure to wedges 32 and 46, more than sufficient for most well bore conditions.

Second Packer Embodiment

Referring now to FIGS. 3A and 3B, the details of a second squeeze packer embodiment 100 of packing apparatus 10 are shown. While first embodiment 20 incorporates the same configuration and general components as prior art packers made of metal, second packer embodiment 100 and the other embodiments described herein comprise specific design features to accommodate the benefits and problems of using non-metallic components, such as plastic.

Packer 100 comprises a center mandrel 102 on which most of the other components are mounted. Mandrel 102 may be described as a thick cross-sectional mandrel having a relatively thicker wall thickness than typical packer mandrels, including center mandrel 22 of first embodiment 20. A thick cross-sectional mandrel may be generally defined as one in which the central opening therethrough has a diameter less than about half of the outside diameter of the mandrel. That is, mandrel central opening 104 in central mandrel 102 has a diameter less than about half the outside of center mandrel 102. It is contemplated that a thick cross-sectional mandrel will be required if it is constructed from a material having relatively low physical properties. In particular, such materials may include phenolics and similar plastic materials.

An upper support 106 is attached to the upper end of center mandrel 102 at threaded connection 108. In an alternate embodiment, center mandrel 102 and upper support 106 are integrally formed and there is no threaded connection 108. A spacer ring or upper slip support 110 is disposed on the outside of mandrel 102 just below upper support 106. Spacer ring 110 is initially attached to center mandrel 102 by at least one shear pin 112. A downwardly and inwardly tapered shoulder 114 is defined on the lower side of spacer ring 110.

Disposed below spacer ring 110 is an upper slip means 115 comprising slips and a wedge. Referring now to FIGS. 9–11, a new embodiment of upper slip means 115 is characterized as comprising a plurality of separate non-metallic upper slips 116 held in place by a retaining means, such as retaining band or ring 117 extending at least partially around slips 116. Upper slips 116 may be held in place by other types of retaining means as well, such as pins. Slips 116 are preferably circumferentially spaced such that a longitudinally extending gap 119 is defined therebetween.

Each slip 116 has a downwardly and inwardly sloping shoulder 118 forming the upper end thereof. The taper of each shoulder 118 conforms to the taper of shoulder 114 on spacer ring 110, and slips 116 are adapted for sliding engagement with shoulder 114, as will be further described herein.

An upwardly and inwardly facing taper 120 is defined in the lower end of each slip 116. Each taper 120 generally faces the outside of center mandrel 102.

Referring now to FIGS. 12–14, an alternate embodiment of the slips of upper slip means 115 is shown. In this embodiment, a plurality of upper slips 116, are integrally formed at the upper ends thereof such that a ring portion 121 is formed. Ring portion 121 may be considered a retaining means for holding upper slips 116' in their initial position around center mandrel 102. The lower ends of slips 116' extend from ring portion 121 and are circumferentially separated by a plurality of longitudinally extending gaps 123. That is, in the second embodiment upper slip means 115 is a characterized as comprising a single piece molded or otherwise formed from a non-metallic material, such as plastic.

Each slip 116', like each slip 116, has downwardly and inwardly sloping shoulder 118 forming the upper end thereof and generally defined in ring portion 121. Again, the taper of each shoulder 118 conforms to the taper of shoulder 114 on spacer ring 110, and slips 116' are adapted for sliding engagement with shoulder 114, as will be further described herein.

As with slips 116, an upwardly and inwardly facing taper 120 is defined in the lower end of each slip 116'. As before, each taper 120 generally faces the outside of center mandrel 102.

A plurality of inserts or teeth 122 preferably are molded into upper slips 116 or 116'. Inserts 122 may have a generally cylindrical configuration and are positioned at an angle with respect to a central axis of packer 100. Thus, a radially outer edge 124 of each insert 122 protrudes from the corresponding upper slip 116 or 116'. Outer edge 124 is adapted for grippingly engaging well bore 12 when packer 100 is set. It is not intended that inserts 122 be limited to this cylindrical

shape or that they have a distinct outer edge 124. Various shapes of inserts may be used.

Inserts 122 can be made of any suitable hard material. For example, inserts 122 could be hardened steel or a non-metallic hardened material, such as ceramic.

Upper slip means 115 further comprises an upper slip wedge 126 which is disposed adjacent to upper slips 116 or 116' and engages taper 120 therein. Upper slip wedge 126 is initially attached to center mandrel 102 by one or more shear pins 128.

Below upper slip wedge 126 are upper back-up ring 37, upper packer shoe 38, end packer elements 40 separated by center packer element 42, lower packer shoe 44 and lower back-up ring 45 which are substantially the same as the corresponding components in first embodiment packer 20. Accordingly, the same reference numerals are used.

Below lower back-up ring 45 is a lower slip means 133 comprising a lower slip wedge 130 which is initially attached to center mandrel 102 by a shear pin 132. Preferably, lower slip wedge 130 is identical to upper slip wedge 126 except that it is positioned in the opposite direction.

In one new embodiment, lower slip means 133 is characterized as also comprising a plurality of separate non-metallic lower slips 136. Lower slips 136 are preferably identical to upper slips 116, except for a reversal of position, and are initially held in place by retaining means, such as retainer band or ring 117 which extends at least partially around slips 136. Other types of retainer means. such as pins, may also be used to hold slip lower slips 136 in place. Lower slips are preferably circumferentially spaced such that longitudinally extending gaps 135 are defined therebetween. See FIGS. 9–11.

In another embodiment, lower slip means 133 comprises a plurality of lower slips 136' which are integrally formed at the lower ends thereof such that a ring portion 137 is formed. Ring portion 137 may be considered a retaining means for holding lower slips 136' in their initial position around center mandrel 102. It will be seen that lower slips 136' are preferably identical to upper slips 116', except for a reversal in position. See FIGS. 12–14. At the upper ends thereof, slips 136' are circumferentially separated by plurality of longitudinally extending gaps 139.

A downwardly and inwardly facing inner taper 134 in each lower slip 136 or 136' is in engagement with lower slip wedge 130.

Lower slips 136 or 136' have inserts or teeth 138 molded therein which are preferably identical to inserts 122 in upper slips 116 or 116'.

Each lower slip 136 or 136' has a downwardly facing shoulder 140 defined in ring portion 137 which tapers upwardly and inwardly. Shoulders 140 are adapted for engagement with a corresponding shoulder 142 defining the upper end of a valve housing 144. Shoulder 142 also tapers upwardly and inwardly. Thus, valve housing 144 may also be considered a lower slip support 144.

Referring now also to FIG. 3B, valve housing 146 is attached to the lower end of center mandrel 102 at threaded connection 146. A sealing means, such as O-ring 148, provides sealing engagement between valve housing 144 and center mandrel 102.

Below the lower end of center mandrel 102, valve housing 104 defines a longitudinal opening 150 therein having a longitudinal rib 152 in the lower end thereof. At the upper end of opening 150 is an annular recess 154.

Below opening 150, valve housing 144 defines a housing central opening including a bore 156 therein having a closed lower end 158. A plurality of transverse ports 160 are defined through valve housing 144 and intersect bore 156. The wall thickness of valve housing 144 is thick enough to accommodate a pair of annular seal grooves 162 defined in bore 156 on opposite sides of ports 160.

Slidably disposed in valve housing 144 below center mandrel 102 is a sliding valve 164. Sliding valve 164 is the same as, or substantially similar to, sliding valve 66 in first embodiment packer 20. At the upper end of sliding valve 164 are a plurality of upwardly extending collet fingers 166 which initially engage recess 154 in valve housing 144. Sliding valve 164 is shown in an uppermost, closed position in FIG. 3B. It will be seen that the lower end of center mandrel 102 prevents further upward movement of sliding valve 164.

Sliding valve 164 defines a valve central opening 168 therethrough which is in communication with central opening 104 in center mandrel 102. A chamfered shoulder 170 is located at the upper end of valve central opening 168.

Sliding valve 164 defines a plurality of substantially transverse ports 172 therethrough which intersect valve central opening 168. As will be further discussed herein, ports 172 are adapted for alignment with ports 160 in valve housing 144 when sliding valve 164 is in a downward, open position thereof. Rib 152 fits between a pair of collet fingers 166 so that sliding valve 164 cannot rotate within valve housing 144, thus insuring proper alignment of ports 172 and 160. Rib 152 thus provides an alignment means.

A sealing means, such as O-ring 174, is disposed in each seal groove 162 and provides sealing engagement between sliding valve 164 and valve housing 144. It will thus be seen that when sliding valve 164 is moved downwardly to its open position, O-rings 174 seal on opposite sides of ports 172 in the sliding valve.

Referring again to FIG. 3A, a tension sleeve 174 is disposed in center mandrel 102 and attached thereto to threaded connection 176. Tension sleeve 174 has a threaded portion 178 which extends from center mandrel 102 and is adapted for connection to a standard setting tool (not shown) of a kind known in the art.

Below tension sleeve 174 is an internal seal 180 similar to internal seal 64 in first embodiment 20.

Third Packer Embodiment

Referring now to FIGS. 4A and 4B, a third squeeze packer embodiment of the present invention is shown and generally designated by the numeral 200. It will be clear to those skilled in the art that third embodiment 200 is similar to second packer embodiment 100 but has a couple of significant differences.

Packer 200 comprises a center mandrel 202. Unlike center mandrel 102 in second embodiment 100, center mandrel 202 is a thin cross-sectional mandrel. That is, it may be said that center mandrel 102 has a mandrel central opening 204 with a diameter greater than about half of the outside diameter of center mandrel 202. It is contemplated that thin cross-sectional mandrels, such as center mandrel 202, may be made of materials having relatively higher physical properties, such as epoxy resins.

The external components of third packer embodiment 200 which fit on the outside of center mandrel 202 are substantially identical to the outer components on second embodiment 100, and therefore the same reference numerals are shown in FIG. 4A. In a manner similar to second embodiment packer 100, center mandrel 202 and upper support 106 may be integrally formed so that there is no threaded connection 108.

The lower end of center mandrel 202 is attached to a valve housing 206 at threaded connection 208. On the upper end of valve housing 206 is an upwardly and inwardly tapered shoulder 210 against which shoulder 104 on lower slips 136 or 136' are slidably disposed. Thus, valve housing 206 may also be referred to as a lower slip support 206.

Referring now also to FIG. 4B, a sealing means, such as O-ring 212, provides sealing engagement between center mandrel 202 and valve housing 206.

Valve housing 206 defines a housing central opening including a bore 214 therein with a closed lower end 216. At the upper end of bore 214 is an annular recess 218. Valve housing 204 defines a plurality of substantially transverse ports 220 therethrough which intersect bore 214.

Slidably disposed in bore 214 in valve housing 206 is a sliding valve 222. At the upper end of sliding valve 222 are a plurality of collet fingers 224 which initially engage recess 218.

Sliding valve 222 defines a plurality of substantially transverse ports 226 therein which intersect a valve central opening 228 in the sliding valve. Valve central opening 228 is in communication with mandrel central opening 204 in center mandrel 202. At the upper end of central opening 228 is a chamfered shoulder 230.

As shown in FIG. 4B, sliding valve 222 is in an uppermost closed position. It will be seen that the lower end of center mandrel 202 prevents further upward movement of sliding valve 222. When sliding valve 222 is moved downwardly to an open position, ports 226 are substantially aligned with ports 220 in valve housing 206. An alignment means, such as an alignment bolt 232, extends from valve housing 206 inwardly between a pair of adjacent collet fingers 224. A sealing means, such as O-ring 234, provides sealing engagement between alignment bolt 232 and valve housing 206. Alignment bolt 234 prevents rotation of sliding valve 222 within valve housing 204 and insures proper alignment of ports 226 and 220 when sliding valve 222 is in its downwardmost, open position.

The wall thickness of sliding valve 222 is sufficient to accommodate a pair of spaced seal grooves 234 are defined in the outer surface of sliding valve 222, and as seen in FIG. 4B, seal grooves 234 are disposed on opposite sides of ports 220 when sliding valve 222 is in the open position shown. A sealing means, such as seal 236, is disposed in each groove 234 to provide sealing engagement between sliding valve 222 and bore 214 in valve housing 206.

Referring again to FIG. 4A, a tension sleeve 238 is attached to the upper end of center mandrel 202 at threaded connection 240. A threaded portion 242 of tension sleeve 238 extends upwardly from center mandrel 202 and is adapted for engagement with a setting apparatus (not shown) of a kind known in the art.

An internal seal 244 is disposed in the upper end of center mandrel 202 below tension sleeve 238.

Fourth Packer Embodiment

Referring now to FIGS. 5A and 5B, a fourth squeeze packer embodiment is shown and generally designated by the numeral 300. As illustrated, fourth embodiment 300 has the same center mandrel 202, and all of the components positioned on the outside of center mandrel 202 are identical to those in the second and third packer embodiments. Therefore, the same reference numerals are used for these components. Tension sleeve 238 and internal seal 244 positioned on the inside of the upper end of center mandrel 202 are also substantially identical to the corresponding components in third embodiment packer 200 and therefore shown with the same reference numerals.

The difference between fourth packer embodiment 300 and third packer embodiment 200 is that in the fourth embodiment shown in FIGS. 5A and 5B, the lower end of center mandrel 202 is attached to a different valve housing 302 at threaded connection 304. Shoulder 140 on each lower slip 136 or 136' slidingly engages an upwardly and inwardly tapered shoulder 306 on the top of valve housing 302. Thus, valve housing 302 may also be referred to as lower slip support 302.

Referring now to FIG. 5B, a sealing means, such as O-ring 308, provides sealing engagement between the lower end of center mandrel 202 and valve housing 302.

Valve housing 302 defines a housing central opening including a bore 310 therein with a closed lower end 312. A bumper seal 314 is disposed adjacent to end 312.

Valve housing 302 defines a plurality of substantially transverse ports 316 therethrough which intersect bore 310. A sliding valve 318 is disposed in bore 310, and is shown in an uppermost, closed position in FIG. 5B. It will be seen that the lower end of center mandrel 202 prevents upward movement of sliding valve 318. Sliding valve 318 defines a valve central opening 320 therethrough which is in communication with mandrel central opening 204 in center mandrel 202. At the upper end of valve central opening 320 in sliding valve 318 is an upwardly facing chamfered shoulder 322.

On the outer surface of sliding valve 318, a pair of spaced seal grooves 324 are defined. In the closed position shown in FIG. 5B, seal grooves 324 are on opposite sides of ports 316 in valve housing 302. A sealing means, such as seal 326, is disposed in each seal groove 324 and provides sealing engagement between sliding valve 318 and bore 310 in valve housing 302.

When sliding valve 318 is opened, as will be further described herein, the sliding valve 318 is moved downwardly such that upper end 328 thereof is below ports 316 in valve housing 302. Downward movement of sliding valve 318 is checked when lower end 330 thereof contacts bumper seal 314. Bumper seal 314 is made of a resilient material which cushions the impact of sliding valve 31 thereon.

Fifth Packer Embodiment

Referring now to FIGS. 6A and 6B, a fifth squeeze packer embodiment is shown and generally designated by the numeral 400. As illustrated, fifth packer embodiment 400 incorporates the same thick cross-sectional center mandrel 102 as does second packer embodiment 100 shown in FIGS. 3A and 3B. Also, the external components positioned on center mandrel 102 are the same as in the second, third and fourth packer embodiments, so the same reference numerals will be used.

Further, tension sleeve 174 and internal seal 180 in second embodiment 100 are also incorporated in fifth embodiment 400, and therefore these same reference numerals have also been used.

The difference between fifth packer embodiment 400 and second embodiment 100 is that the lower end of center mandrel 102 is attached to a lower slip support 402 at threaded connection 404. Shoulders 140 on lower slips 136 or 136' slidingly engage an upwardly and inwardly tapered shoulder 406 at the upper end of lower slip support 402.

Referring now to FIG. 6B, a sealing means, such as O-ring 408, provides sealing engagement between the lower end of center mandrel 102 and lower slip support 402.

Lower slip support 402 defines a first bore 410 therein and a larger second bore 412 spaced downwardly from the first bore. A tapered seat surface 414 extends between first bore 410 and second bore 412.

The lower end of lower support 402 is attached to a valve housing 416 at threaded connection 418. Valve housing 416 defines a first bore 420 and a smaller second bore 422 therein. An upwardly facing annular shoulder 424 extends between first bore 420 and second bore 422. Below second bore 422, valve housing 416 defines a third bore 426 therein with an internally threaded surface 428 forming a port at the lower end of the valve housing.

Disposed in first bore 420 in valve housing 416 is a valve body 430 with an upwardly facing annular shoulder 432 thereon. An elastomeric valve seal 434 and a valve spacer 436, which provides support for the valve seal, are positioned adjacent to shoulder 432 on valve body 430. A conical valve head 438 is positioned above valve seal 434 and is attached to valve body 430 at threaded connection 440. It will be seen by those skilled in the art that valve seal 434 is adapted for sealing engagement with seat surface 414 in lower slip support 402 when valve body 430 is moved upwardly.

The lower end of valve body 430 is connected to a valve holder 442 by one or more pins 444. Valve holder 442 is disposed in second bore 422 of valve housing 416. A sealing means, such as O-ring 446 provides sealing engagement between valve holder 442 and valve housing 416.

Above shoulder 424 in valve housing 416, valve body 430 has a radially outwardly extending flange 448 thereon. A biasing means, such as spring 450, is disposed between flange 448 and shoulder 424 for biasing valve body 430 upwardly with respect to valve housing 416.

Valve holder 442 defines a first bore 452 and a smaller second bore 454 therein with an upwardly facing chamfered shoulder 456 extending therebetween. A ball 458 is disposed in valve holder 442 and is adapted for engagement with shoulder 456.

First Bridge Plug Embodiment

Referring now to FIG. 7, a first bridge plug embodiment of the present invention is shown and generally designated by the numeral 500. First bridge plug embodiment 500 comprises the same center mandrel 102 and the external components positioned thereon as does the second packer embodiment 100. Therefore, the reference numerals for these components shown in FIG. 7 are the same as in FIG. 3A.

The lower end of center mandrel 102 in first bridge plug embodiment 500 is connected to a lower slip support 502 at threaded connection 504. An upwardly and inwardly tapered shoulder 506 on lower slip support 502 engages shoulders 140 on lower slips 136 or 136'. As with the other embodiments, slips 136 or 136' are adapted for sliding along shoulder 506.

Lower slip support 502 defines a bore 508 therein which is in communication with mandrel central opening 104 in center mandrel 102.

A bridging plug 510 is disposed in the upper portion of mandrel central opening 104 in center mandrel 102 and is sealingly engaged with internal seal 180. A radially outwardly extending flange 512 prevents bridging plug 510 from moving downwardly through center mandrel 102.

Above bridging plug 510 is tension sleeve 174, previously described for second packer embodiment 100.

Second Bridge Plug Embodiment

Referring now to FIG. 8, a second bridge plug embodiment of the present invention is shown and generally designated by the numeral 600. Second bridge plug embodiment 600 uses the same thin cross-sectional mandrel 202 as does third packer embodiment 200 shown in FIG. 4A. Also, the external components positioned on center mandrel 202 are the same as previously described, so the same reference numerals are used in FIG. 8.

In second bridge plug embodiment 600, the lower end of center mandrel 202 is attached to the same lower slip support 502 as first bridge plug embodiment 500 at threaded connection 602. It will be seen that bore 508 in lower slip support 502 is in communication with mandrel central opening 204 in center mandrel 202.

A bridging plug 604 is positioned in the upper end of mandrel central opening 204 in center mandrel 202. A shoulder 608 in central opening 204 prevents downward movement of bridging plug 604. A sealing means, such as a plurality of O-rings 606, provide sealing engagement between bridging plug 604 and center mandrel 202.

Tension sleeve 238, previously described, is positioned above bridging plug 604.

Setting And Operation Of The Apparatus

Downhole tool apparatus 10 is positioned in well bore 12 and set into engagement therewith in a manner similar to prior art devices made with metallic components. For example, a prior art apparatus and setting thereof is disclosed in the above-referenced U.S. Pat. No. 4,151,875 to Sullaway. This patent is incorporated herein by reference.

For first packer embodiment 20, the setting tool pulls upwardly on tension sleeve 62, and thereby on mandrel 22, while holding lock ring housing 24. The lock ring housing is thus moved relatively downwardly along mandrel 22 which forces upper slips 28 outwardly and shears screws 36, pushing upper slip wedge 32 downwardly against packer elements 40 and 42. Screws 50 are also sheared and lower slip wedge 46 is pushed downwardly toward lower slip support 58 to force lower slips 54 outwardly. Eventually, upper slips 28 and lower slips 54 are placed in gripping engagement with well bore 12 and packer elements 40 and 42 are in sealing engagement with the well bore. The action of upper slips 28 and 54 prevent packer 20 from being unset. As will be seen by those skilled in the art, pressure below packer 20 cannot force the packer out of well bore 12, but instead, causes it to be even more tightly engaged.

Eventually, in the setting operation, tension sleeve 62 is sheared, so the setting tool may be removed from the well bore.

The setting of second packer embodiment 100, third packer embodiment 200, fourth packer embodiment 300, fifth packer embodiment 400, first bridge plug embodiment 500 and second bridge plug embodiment 600 is similar to that for first packer embodiment 20. The setting tool is attached to either tension sleeve 174 or 238. During setting, the setting tool pushes downwardly on upper slip support 110, thereby shearing shear pin 112. Upper slips 116 or 116' are moved downwardly with respect to upper slip wedge 126. Tapers 120 in upper slips 116 or 116' slide along upper slip wedge 126, and shoulders 118 on upper slips 116 or 116' slide along shoulder 114 on upper slip support 110. Thus, upper slips 116 or 116' are forced radially outwardly with respect to center mandrel 102 or 202.

As this outward force is applied to slips 116 in the embodiment of FIGS. 9-11, retaining band 117 is broken, and slips 116 are freed to move radially outwardly such that edges 124 of inserts 122 grippingly well bore 12.

As the outward force is applied to alternate embodiment slips 116' (FIGS. 12-14), ring portion 121 will fracture, probably starting at the base of each gap 123. A typical fracture line 125 is shown in FIGS. 12 and 13. In other words, slips 116' separate and are freed to move radially outwardly such that edges 124 of inserts 122 grippingly engage well bore 12.

Also during the setting operation, upper slip wedge 126 is forced downwardly, shearing shear pin 128. This in turn causes packer elements 40 and 42 to be squeezed outwardly into sealing engagement with the well bore.

The lifting on center mandrel 102 or 202 causes the lower slip support (valve housing 144 in first packer embodiment 100, valve housing 206 in second packer embodiment 200, valve housing 302 in fourth packer embodiment 300, lower slip support 402 in fifth packer embodiment 400, and lower slip support 502 in first bridge plug embodiment 500 and second bridge plug embodiment 600) to be moved up and lower slips 136 or 136' to be moved upwardly with respect to lower slip wedge 130. Tapers 134 in lower slips 136 or 136' slide along lower slip wedge 130, and shoulders 140 on lower slips 136 or 136' slide along the corresponding shoulder 142, 210, 306, 406, or 506. Thus, lower slips 136 or 136' are forced radially outwardly with respect to center mandrel 102 or 202.

As this force is applied to slips 136 in the embodiment of FIGS. 9-11, retaining band 117 is broken, and slips 136 are freed to move radially outwardly such that edges 124 of inserts 138 grippingly engage well bore 12.

As the outward force is applied to alternate embodiment slips 136' (FIGS. 12-14), ring portion 137 will fracture, probably starting at the base of each gap 139. A typical fracture line 125 is shown in FIGS. 12 and 13. In other words, slips 136' separate and are freed to move radially outwardly such that edges 124 of inserts 138 grippingly engage well bore 12.

Also during the setting operation, lower slip wedge 130 is forced upwardly, shearing shear pin 132, to provide additional squeezing force on packer elements 40 and 42.

The engagement of inserts 122 in upper slips 116 or 116' and inserts 138 in lower slips 136 or 136' with well bore 12 prevent packers 100, 200, 300, 400 and bridge plugs 500, 600 from coming unset.

Once any of packers 20, 100, 200, 300, 400 are set, the valves therein may be actuated in a manner known in the art. Sliding valve 164 in second packer embodiment 126, and sliding valve 22 in third packer embodiment 200 are set in a similar, if not identical manner. Sliding valve 318 in fourth packer embodiment 300 is also set in a similar manner, but does not utilize collets, nor is alignment of sliding valve 318 with respect to ports 316 in valve housing 302 important. Sliding valve 318 is simply moved below ports 316 to open the valve. Bumper seal 314 cushions the downward movement of sliding valve 318, thereby minimizing the possibility of damage to sliding valve 318 or valve housing 302 during an opening operation.

In fifth packer embodiment 400, the valve assembly comprising valve body 432, valve seal 434, valve spacer 436, valve head 438 and valve holder 442 is operated in a manner substantially identical to that of the Halliburton EZ Drill ® squeeze packer of the prior art.

Drilling Out The Packer Apparatus

Drilling out any embodiment of downhole tool 10 may be carried out by using a standard drill bit at the end of tubing string 16. Cable tool drilling may also be used. With a standard "tri-cone" drill bit, the drilling operation is similar to that of the prior art except that variations in rotary speed and bit weight are not critical because the non-metallic materials are considerably softer than prior art cast iron, thus making tool 10 much easier to drill out. This greatly simplifies the drilling operation and reduces the cost and time thereof.

In addition to standard tri-cone drill bits, and particularly if tool 10 is constructed utilizing engineering grade plastics for the mandrel as well as for slip wedges, slips, slip supports and housings, alternate types of drill bits may be used which would be impossible for tools constructed substantially of cast iron. For example, polycrystalline diamond compact (PDC) bits may be used. Drill bit 14 in FIG. 1 is illustrated as a PDC bit. Such drill bits have the advantage of having no moving parts which can jam up. Also, if the well bore itself was drilled with a PDC bit, it is not necessary to replace it with another or different type bit in order to drill out tool 10.

While specific squeeze packer and bridge plug configurations of packing apparatus 10 has been described herein, it will be understood by those skilled in the art that other tools may also be constructed utilizing components selected of non-metallic materials, such as engineering grade plastics.

Additionally, components of the various packer embodiments may be interchanged. For example, thick cross-sectional center mandrel 102 may be used with valve housing 206 in second packer embodiment 200 or valve housing 302 in fourth packer embodiment 300. Similarly, thin cross-sectional center mandrel 202 could be used with valve body 144 in second packer embodiment 100 or lower slip support 402 and valve housing 416 in fifth packer embodiment 400. The intent of the invention is to provide devices of flexible design in which a variety of configurations may be used.

It will be seen, therefore, that the downhole tool packer apparatus and methods of drilling thereof of the present invention are well adapted to carry out the ends and advantages mentioned as well as those inherent therein. While presently preferred embodiments of the apparatus and various drilling methods have been discussed for the purposes of this disclosure, numerous

changes in the arrangement and construction of parts and the steps of the methods may be made by those skilled in the art. In particular, the invention is not intended to be limited to squeeze packers or bridge plugs. All such changes are encompassed within the scope and spirit of the appended claims.

What is claimed is:

1. A downhole apparatus for use in a well bore, said apparatus comprising:
   a center mandrel; and
   slip means disposed on said mandrel for grippingly engaging said well bore when in a set position, said slip means being at least partially made of a non-metallic material.

2. The apparatus of claim 1 characterized as a packing apparatus and further comprising packing means disposed on said mandrel for sealingly engaging said well bore when in a set position.

3. The apparatus of claim 2 wherein said slip means is an upper slip means disposed above said packing means and further comprising a lower slip means disposed below said packing means, said lower slip means being at least partially made of a non-metallic material.

4. The apparatus of claim 1 wherein said slip means comprises a slip support made of a non-metallic material.

5. The apparatus of claim 1 wherein said slip means comprises a slip wedge made of non-metallic material.

6. The apparatus of claim i wherein said slip means comprises:
   a plurality of non-metallic slips disposed in an initial position around said mandrel; and
   retaining means for holding said slips in said initial position.

7. The apparatus of claim 6 wherein said retaining means is characterized by a retaining band extending at least partially around said slips.

8. The apparatus of claim 6 wherein said retaining means comprises a non-metallic ring portion integrally formed with said slips and being fracturable during a setting operation, whereby said slips are separated.

9. The apparatus of claim 8 wherein said slips define a plurality of gaps therebetween adjacent to an end of said slips.

10. The apparatus of claim 6 further comprising a plurality of hardened inserts molded into said slips

11. The apparatus of claim 10 wherein said inserts are steel.

12. The apparatus of claim 10 wherein said inserts are made of a non-metallic material.

13. The apparatus of claim 12 wherein said inserts are made of a ceramic material.

14. The apparatus of claim 1 wherein said non-metallic material is an engineering grade plastic.

15. The apparatus of claim 14 wherein said plastic is nylon.

16. The apparatus of claim 14 wherein said plastic is a phenolic material.

17. The apparatus of claim 16 wherein said phenolic material is one of Fiberite FM4056J, Fiberite FM4005 and Resinoid 1360.

18. The apparatus of claim 14 wherein said plastic is an epoxy resin.

19. A downhole apparatus for use in a well bore, said apparatus comprising:
   a center mandrel;
   a slip wedge disposed around said mandrel;
   a plurality of separate non-metallic slips disposed around said mandrel adjacent to said wedge; and
   retaining means for retaining said slips in an initial position out of engagement with the well bore.

20. The apparatus of claim 19 wherein said wedge is made of a non-metallic material.

21. The apparatus of claim 19 wherein said slips are made of engineering grade plastic.

22. The apparatus of claim 21 wherein said plastic is nylon.

23. The apparatus of claim 21 wherein said plastic is a phenolic material.

24. The apparatus of claim 21 wherein said phenolic material is Fiberite FM4056J.

25. The apparatus of claim 21 wherein said plastic is an epoxy resin.

26. The apparatus of claim 19 further comprising a plurality of inserts molded into said slips for grippingly engaging the well bore when in a set position.

27. The apparatus of claim 26 wherein said inserts are hardened steel.

28. The apparatus of claim 26 wherein said inserts are made of a non-metallic material.

29. The apparatus of claim 28 wherein said inserts are made of a ceramic material.

30. A downhole apparatus for use in a well bore, said apparatus comprising:
   a center mandrel;
   a slip wedge disposed around said mandrel;
   a plurality of non-metallic slips disposed around said mandrel adjacent to said wedge; and
   a non-metallic ring integrally formed at an end of each of said slips and adapted for holding said slips in an initial position out of engagement with the well bore.

31. The apparatus of claim 30 wherein said wedge is made of a non-metallic material.

32. The apparatus of claim 31 wherein said slips define a plurality of longitudinally extending gaps therebetween adjacent to an opposite end of said slips from said ring.

33. The apparatus of claim 30 wherein said ring is made of a fracturable engineering grade plastic.

34. The apparatus of claim 33 wherein said plastic is nylon.

35. The apparatus of claim 33 wherein said plastic is a phenolic material.

36. The apparatus of claim 33 wherein said phenolic material is Fiberite FM4056J.

37. The apparatus of claim 33 wherein said plastic is an epoxy resin.

38. The apparatus of claim 30 further comprising a plurality of inserts molded into said slips for grippingly engaging the well bore when in a set position.

39. The apparatus of claim 38 wherein said inserts are hardened steel.

40. The apparatus of claim 38 wherein said inserts are made of a non-metallic material.

41. The apparatus of claim 38 wherein said inserts are made of a ceramic material.

* * * * *

CERTIFICATE OF NAME CHANGE

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State of Delaware

Office of the Secretary of State

I, EDWARD J. FREEL, SECRETARY OF STATE OF THE STATE OF DELAWARE, DO HEREBY CERTIFY THE ATTACHED IS A TRUE AND CORRECT COPY OF THE CERTIFICATE OF AGREEMENT OF MERGER, WHICH MERGES:

"HALLIBURTON MERGE CO.", A DELAWARE CORPORATION,

WITH AND INTO "HALLIBURTON COMPANY" UNDER THE NAME OF "HALLIBURTON ENERGY SERVICES, INC.", A CORPORATION ORGANIZED AND EXISTING UNDER THE LAWS OF THE STATE OF DELAWARE, AS RECEIVED AND FILED IN THIS OFFICE THE TWELFTH DAY OF DECEMBER, A.D. 1996, AT 11:30 O'CLOCK A.M.

Edward J. Freel

Edward J. Freel, Secretary of State

AUTHENTICATION: 8275637

DATE: 01-07-97

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STATE OF DELAWARE
SECRETARY OF STATE
DIVISION OF CORPORATIONS
FILED 11:30 AM 12/12/1996
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AGREEMENT AND PLAN OF

REORGANIZATION

among Halliburton Company,

Halliburton Hold Co. and Halliburton Merge Co.

dated as of December 11, 1996

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AGREEMENT AND PLAN OF REORGANIZATION

THIS AGREEMENT AND PLAN OF REORGANIZATION ("Agreement"), dated as of December 11, 1996, is among Halliburton Company, a Delaware corporation (the "Company"), Halliburton Hold Co., a Delaware corporation ("Holdco") and a direct, wholly owned subsidiary of the Company, and Halliburton Merge Co., a Delaware corporation ("Mergeco") and a direct, wholly owned subsidiary of Halliburton Delaware, Inc., a Delaware corporation ("Newco") that is itself a direct, wholly owned subsidiary of Holdco.

RECITALS

A. The Company's authorized capital stock consists of (i) 200,000,000 shares of common stock, par value $2.50 per share ("Company Common Stock"), of which 125,258,208 shares were issued and outstanding as of November 30, 1996 and 4,012,502 shares were held in treasury on such date, and (ii) 5,000,000 shares of preferred stock, without par value, none of which is currently outstanding but of which 2,000,000 shares have been designated as the Halliburton Company Series A Junior Participating Preferred Stock ("Company Series A Preferred Stock").

B. As of the date hereof, Holdco's authorized capital stock consists of (i) 200,000,000 shares of common stock, par value $2.50 per share ("Holdco Common Stock"), of which 1,000 shares are issued and outstanding and no shares are held in treasury, and (ii) 5,000,000 shares of preferred stock, without par value, none of which is currently outstanding but of which 2,000,000 shares have been designated as the Halliburton Hold Co. Series A Junior Participating Preferred Stock ("Holdco Series A Preferred Stock").

C. The designations, rights and preferences, and the qualifications, limitations and restrictions thereof, of the Holdco Series A Preferred Stock and the Holdco Common Stock are the same as those of the Company Series A Preferred Stock and the Company Common Stock.

D. The Certificate of Incorporation and the By-laws of Holdco immediately after the Effective Time (as hereinafter defined) will contain provisions identical to the Certificate of Incorporation and By-laws of the Company immediately before the Effective Time (other than with respect to matters excepted by Section 251(g) of the General Corporation Law of the State of Delaware (the "DGCL")).

E. The directors of the Company immediately prior to the Merger (as hereinafter defined) will be the directors of Holdco as of the Effective Time.

F. Holdco, Newco and Mergeco are newly formed corporations organized for the purpose of participating in the transactions herein contemplated.

G. The Company desires to create a new holding company structure by merging Mergeco with and into the Company with the Company being the surviving corporation, and converting each outstanding share of Company Common Stock into a like number of shares of Holdco Common Stock, all in accordance with the terms of this Agreement.

H. The Boards of Directors of Holdco, Mergeco and the Company have approved this Agreement and the merger of Mergeco with and into the Company upon the terms and subject to the conditions set forth in this Agreement (the "Merger").

I. Pursuant to authority granted by the Board of Directors of the Company, the Company will, immediately prior to the Effective Time of the Merger, contribute to the capital of Holdco all of the shares of Company Common Stock then held by the Company in its treasury.

NOW, THEREFORE, in consideration of the premises and the covenants and agreements contained in this Agreement, and intending to be legally bound hereby, the Company, Holdco and Mergeco hereby agree as follows:

ARTICLE I
THE MERGER

Section 1.1 *The Merger*. In accordance with Section 251(g) of the DGCL and subject to and upon the terms and conditions of this Agreement, Mergeco shall, at the Effective Time, be merged with and into the Company, the separate corporate existence of Mergeco shall cease and the Company shall continue as the surviving corporation. The Company as the surviving corporation after the Merger is hereinafter sometimes referred to as the "Surviving Corporation." At the Effective Time, the effect of the Merger shall be as provided in Section 259 of the DGCL.

Section 1.2 *Effective Time*. The Merger shall become effective upon the filing, after the date hereof and on or before December 31, 1996, of a copy of this Agreement with the Secretary of State of the State of Delaware (the time of such filing being referred to herein as the "Effective Time").

Section 1.3 *Certificate of Incorporation.* From and after the Effective Time the Composite Certificate of Incorporation of the Company, as in effect immediately prior to the Effective Time, shall be the certificate of incorporation of the Surviving Corporation until thereafter amended as provided by law; *provided, however*, that, from and after the Effective Time:

(a) Article One thereof shall be amended so as to read in its entirety as follows:

"First: The name of this Corporation is Halliburton Energy Services, Inc."

(b) Article Fourth thereof shall be amended so as to read in its entirety as follows:

"Fourth: The aggregate number of shares which the Corporation shall have authority to issue shall be one thousand (1,000), consisting of one thousand (1,000) shares of Common Stock, par value $1.00 per share. No shares of the previously designated Series A Junior Participating Preferred Stock having been issued, such series is hereby terminated and all matters set forth in this certificate of incorporation with respect to such series are hereby eliminated from this certificate of incorporation."

(c) A new Article Seventeenth shall be added thereto which shall be and read in its entirety as follows:

"Seventeenth: Any act or transaction by or involving the Corporation that requires for its adoption under the General Corporation Law of the State of Delaware or its certificate of incorporation the approval of the stockholders of the Corporation shall, by virtue of this reference to Section 251(g) of the General Corporation Law of the State of Delaware, require, in addition, the approval of the stockholders of Halliburton Company, a Delaware corporation (formerly Halliburton Hold Co.), or any successor thereto by merger, so long as such corporation or its successor is the ultimate parent, directly or indirectly, of this Corporation, by the same vote that is required by the General Corporation Law of the State of Delaware and/or the certificate of incorporation of this Corporation. For the purposes of this Article Seventeenth, the term "parent" shall mean a corporation that owns, directly or indirectly, at least a majority of the outstanding capital stock of this Corporation entitled to vote in the election of directors of this Corporation without regard to the occurrence of any contingency."

Section 1.4 *By-laws*. From and after the Effective Time, the By-laws of Mergeco, as in effect immediately prior to the Effective Time, shall be the By-laws of the Surviving Corporation until thereafter amended as provided therein or by applicable law.

Section 1.5 *Directors*. The directors of Mergeco immediately prior to the Effective Time shall be the initial directors of the Surviving Corporation and will hold office from the Effective Time until their successors are duly elected or appointed and qualified in the manner provided in the Certificate of Incorporation and the By-laws of the Surviving Corporation or as otherwise provided by law.

Section 1.6 *Officers*. The officers of Mergeco immediately prior to the Effective Time shall be the initial officers of the Surviving Corporation and will hold office from the Effective Time until their successors are duly elected or appointed and qualified in the manner provided in the Certificate of Incorporation and the By-laws of the Surviving Corporation or as otherwise provided by law.

Section 1.7 *Additional Actions*. Subject to the terms of this Agreement, the parties hereto shall take all such reasonable and lawful action as may be necessary or appropriate in order to effectuate the Merger. If, at any time after the Effective Time, the Surviving Corporation shall consider or be advised that any deeds, bills of sale, assignments, assurances or any other actions or things are necessary or desirable to vest, perfect or confirm, of record or otherwise, in the Surviving Corporation its right, title or interest in, to or under any of the rights, properties or assets of either of Mergeco or the Company acquired or to be acquired by the Surviving Corporation as a result of, or in connection with, the Merger or otherwise to carry out this Agreement, the officers and directors of the Surviving Corporation shall be authorized to execute and deliver, in the name and on behalf of each of Mergeco and the Company, all such deeds, bills of sale, assignments and assurances and to take and do, in the name and on behalf of each of Mergeco and the Company or otherwise, all such other actions and things as may be necessary or desirable to vest, perfect or confirm any and all right, title and interest in, to and under such rights, properties or assets in the Surviving Corporation or otherwise to carry out this Agreement.

Section 1.8 *Conversion of Securities*. At the Effective Time, by virtue of the Merger and without any action on the part of Holdco, Mergeco, the Company or the holder of any of the following securities:

(a) Each share of Company Common Stock issued and outstanding immediately prior to the Effective Time shall be converted into and thereafter represent one duly issued, fully paid and nonassessable share of Holdco Common Stock.

(b) Each share of Company Common Stock issued but held by Holdco in its treasury immediately prior to the Effective Time shall be converted into and thereafter represent one duly issued, fully paid and nonassessable share of Holdco Common Stock held by Holdco in its treasury immediately after the Effective Time of the Merger.

(c) Each share of common stock, par value $1.00 per share, of Mergeco issued and outstanding immediately prior to the Effective Time shall be converted into and thereafter represent one duly issued, fully paid and nonassessable share of common stock, par value $1.00 per share, of the Surviving Corporation.

(d) From and after the Effective Time, holders of certificates formerly evidencing Company Common Stock shall cease to have any rights as stockholders of the Company, except as provided by law; *provided, however,* that such holders shall have the rights set forth in Section 1.10 herein.

Section 1.9 *Preferred Share Purchase Rights.*

(a) In accordance with Section 36 of that certain Second Amended and Restated Rights Agreement dated as of December 15, 1995, as thereafter amended, between the Company and ChaseMellon Shareholder Services, L.L.C., as Rights Agent (the "Company Rights Plan"), each outstanding preferred share purchase right of the Company ("Company Purchase Right") shall terminate as of the Effective Time.

(b) Holdco shall, prior to the Effective Time, adopt a preferred share purchase rights plan (the "Holdco Rights Plan") substantially similar in form and substance to the Company Rights Plan and, in accordance therewith, Holdco shall, at the Effective Time but without duplication of Holdco's obligations under the Holdco Rights Plan, issue to each holder of Holdco Common Stock issued pursuant hereto one preferred share purchase right ("Holdco Purchase Right") for each share of Holdco Common Stock issued by it pursuant to Section 1.8(a) herein.

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Section 1.10 *No Surrender of Certificates: Stock Transfer Books.* As a result of the provisions of Section 1.3 herein, in conjunction with the provisions of a certificate of amendment of certificate of incorporation of Holdco to be filed with the Secretary of State of the State of Delaware and to become effective immediately after the Effective Time, the corporate name of Holdco immediately following the Effective Time will be "Halliburton Company", the same name as the corporate name of the Company immediately prior to the Effective Time. Accordingly, until thereafter surrendered for transfer or exchange in the ordinary course, each outstanding certificate that, immediately prior to the Effective Time, evidenced Company Common Stock shall be deemed and treated for all corporate purposes to evidence the ownership of the number of shares of Holdco Common Stock into which such shares of Company Common Stock were converted pursuant to the provisions of Sections 1.8 (a) and (b) herein. In addition, immediately after the Effective Time, each such certificate shall also evidence a number of Holdco Purchase Rights equal to the number of Company Purchase Rights evidenced thereby immediately prior to the Effective Time of the Merger.

ARTICLE II
ACTIONS TO BE TAKEN IN CONNECTION WITH THE MERGER

Section 2.1 *Company Indebtedness.* As of the date of this Agreement, the Company is a party to the following indentures (individually, an "Indenture" and, collectively, the "Indentures"):

(1) Senior Indenture (the "First Senior Indenture") dated as of January 2, 1991 between the Company and Texas Commerce Bank National Association, as trustee, pursuant to which the Company has heretofore issued $200 million in aggregate principal amount of a series of 8.75% Debentures due February 15, 2021 (the "Debentures"), all of which currently remain outstanding; and

(2) Second Senior Indenture (the "Second Senior Indenture") dated as of December 1, 1996 between the Company and Texas Commerce Bank National Association, as trustee, pursuant to which no debt securities are currently outstanding; and

(3) Subordinated Indenture (the "Subordinated Indenture") dated as of January 2, 1991 between the Company and Texas Commerce Bank National Association, as trustee, pursuant to which no debt securities are currently outstanding.

As of the Effective Time, Holdco and the Company shall, with respect to each such Indenture and, in the case of the First Senior Indenture, with respect to the Debentures outstanding thereunder,

together with the trustee under each Indenture, execute, acknowledge and deliver indentures supplemental (each, a "Supplemental Indenture") to each of such Indentures pursuant to which Holdco shall assume and agree to perform all obligations of the Company thereunder without, subject to certain exceptions set forth in such Supplemental Indentures, releasing the Company from such obligations and Holdco will agree to pay, perform and discharge all obligations of the Company under the Debentures.

Section 2.2 *Assumption of Benefit Plans.* Holdco and the Company hereby agree that they will, at the Effective Time, execute, acknowledge and deliver an assumption agreement pursuant to which Holdco will, from and after the Effective Time, assume and agree to perform all obligations of the Company pursuant to the Halliburton Company Career Executive Incentive Stock Plan, the 1993 Stock and Long-Term Incentive Plan, the Landmark Graphics Corporation 1984 Incentive Stock Option Plan, the Landmark Graphics Corporation 1985 Incentive Stock Option Plan, the Landmark Graphics Corporation 1987 Nonqualified Stock Option Plan, the Landmark Graphics Corporation 1989 Flexible Stock Option Plan, the Landmark Graphics Corporation Directors' Stock Option Plan, the Landmark Graphics Corporation Consultants' Stock Option Plan, the Landmark Graphics Corporation 1990 Employee Stock Option Plan and the Landmark Graphics Corporation 1994 Flexible Incentive Plan (the "Benefit Plans").

Section 2.3 *Reservation of Shares.* On or prior to the Effective Time, Holdco will reserve sufficient shares of Holdco Common Stock to provide for the issuance of Holdco Common Stock upon exercise of options outstanding under the Benefit Plans and will reserve a number of shares of Holdco Series A Preferred Stock sufficient to provide for the issuance thereof upon exercise of Holdco Purchase Rights.

ARTICLE III
CONDITIONS OF MERGER

Section 3.1 *Conditions Precedent.* The obligations of the parties to this Agreement to consummate the Merger and the transactions contemplated by this Agreement shall be subject to fulfillment or waiver by the parties hereto of each of the following conditions:

(a) Prior to the Effective Time, the Holdco Common Stock to be issued pursuant to the Merger shall have been approved for listing, upon official notice of issuance, by the New York Stock Exchange.

(b) Holdco shall have adopted the Holdco Rights Plan and distributed Holdco Purchase Rights as a dividend on the then issued and outstanding shares of Holdco Common Stock, and, prior to the Effective Time, the Holdco Purchase Rights to be issued in conjunction with the issuance of Holdco Common Stock pursuant to the Merger shall have been approved for listing, upon official notice of issuance, by the New York Stock Exchange.

(c) The Company, Holdco and the Trustee shall have executed and delivered the Supplemental Indentures contemplated by Article II herein subject only to the occurrence of the Effective Time of the Merger.

(d) Prior to the Effective Time, the Company shall have received certain revenue rulings from the Internal Revenue Service requested by it pursuant to a letter dated August 30, 1996, to the Internal Revenue Service from Vinson & Elkins L.L.P., counsel to the Company.

(e) Prior to the Effective Time, Vinson & Elkins L.L.P., counsel to the Company, shall have received an interpretive or no-action letter from the Securities and Exchange Commission, in form and substance satisfactory to the Company, in response to that certain request therefor dated December 6, 1996 from such firm.

(f) Prior to the Effective Time, Vinson & Elkins L.L.P., counsel to the Company, shall have rendered an opinion to the Board of Directors of the Company, in form and substance satisfactory to the Company, to the effect that the Merger will constitute a tax-free reorganization under Section 368(a) of the Code and that no gain or loss will be recognized by the stockholders of the Company upon receipt to the Holdco Common Stock in exchange for their shares of Company Common Stock pursuant to the Merger.

(g) Prior to the Effective Time, no order, statute, rule, regulation, executive order, injunction, stay, decree, judgment or restraining order shall have been enacted, entered, promulgated or enforced by any court or governmental or regulatory authority or instrumentality which prohibits or makes illegal the consummation of the Merger or the transactions contemplated hereby.

ARTICLE IV
COVENANTS

Section 4.1 *Election of Directors.* Effective as of the Effective Time, the Company, in its capacity as the sole stockholder of Holdco, will remove each of the then directors of Holdco, will cause the board of directors of Holdco to effect such amendments to the bylaws of Holdco as are necessary to increase the number of directors of Holdco to equal the number of directors of the Company and will elect each person who is then a member of the board of directors of the Company as a director of Holdco, each of whom shall serve until the next annual meeting of shareholders of Holdco and until his successor shall have been elected and qualified.

Section 4.2 *Listing of Holding Company Common Stock.* Holdco will use its best efforts to obtain, at or before the Effective Time, authorization to list, upon official notice of issuance, on the New York Stock Exchange Holdco Common Stock issuable pursuant to the Merger and Holdco Purchase Rights issuable in conjunction therewith.

Section 4.3 *Employee Benefit Plans.* The Company and Holdco will take or cause to be taken all actions necessary or desirable in order for Holdco to assume the Benefit Plans and to assume (or become a participating employer in) each other existing employee benefit plan and agreement of the Company, with or without amendments, or to adopt comparable plans, all to the extent deemed appropriate by the Company and Holdco and permitted under applicable law.

Section 4.4 *Change in Capitalization.* Prior to the Effective Time, Holdco and the Company agree to take all action necessary or desirable under the DGCL to designate 2,000,000 shares of Preferred Stock of Holdco as Series A Junior Participating Preferred Stock having terms and provisions substantially similar to those of the Company's Series A Junior Participating Preferred Stock.

Section 4.5 *Change of Name of Holdco.* Holdco and the Company will take or cause to be taken all such actions as may be necessary or desirable to effect an amendment to the Certificate of Incorporation of Holdco immediately after the Effective Time changing the name of Holdco to "Halliburton Company".

Section 4.6 *Contribution of Treasury Stock.* Immediately prior to the Effective Time, the Company will contribute to the capital of Holdco all the Company Common Stock then held in the treasury of the Company.

Section 4.7 *Contribution of Outstanding Holdco Stock.* At the Effective Time, the Company will contribute to the capital of Holdco all shares of Holdco Common Stock and all Holdco Purchase Rights outstanding immediately prior to the Merger and owned of record and beneficially by the Company.

Section 4.8 *Contribution of Alphabet Stock.* Prior to the Merger, the Company shall cause Brown & Root Holdings, Inc., a Delaware corporation ("BRHI"), to contribute all the outstanding capital stock designated Series B issued by Halliburton Holdings, Inc. ("HHI") and owned by BRHI to Brown & Root, Inc., a Texas corporation.

Section 4.9 *InterCompany Stock Distributions.* Promptly after the Effective Time, the Surviving Corporation shall contribute the stock of certain controlled foreign corporations to its direct, wholly owned subsidiary Halliburton Affiliates Corporation, a Delaware corporation ("HAC") and the stock of HHI owned by the Surviving Corporation to Halliburton International, Inc. ("HII"); promptly thereafter the Surviving Corporations shall distribute to Newco all of the outstanding stock of BRHI, HII, Landmark Graphics Corporation and HAC.

ARTICLE V
TERMINATION AND AMENDMENT

Section 5.1 *Termination.* This Agreement may be terminated and the Merger contemplated hereby may be abandoned at any time prior to the Effective Time by action of the Board of Directors of the Company, Holdco or Mergeco if it should determine that for any reason the completion of the transactions provided for herein would be inadvisable or not in the best interest of such corporation or its stockholders. In the event of such termination and abandonment, this Agreement shall become void and neither the Company, Holdco or Mergeco nor their respective stockholders, directors or officers shall have any liability with respect to such termination and abandonment.

Section 5.2 *Amendment.* This Agreement may be supplemented, amended or modified by the mutual consent of the Boards of Directors of the parties to this Agreement.

ARTICLE VI
MISCELLANEOUS PROVISIONS

Section 6.1 *Governing Law.* Except with respect to matters contained herein governed by the DGCL, this Agreement has been executed and delivered in the State of Texas and shall be

governed by and construed and enforced under the laws of the State of Texas, regardless of the laws that might otherwise govern under applicable Texas principles of conflicts of law.

Section 6.2 *Counterparts*. This Agreement may be executed in one or more counterparts, each of which when executed shall be deemed to be an original but all of which shall constitute one and the same agreement.

Section 6.3 *Entire Agreement*. This Agreement, including the documents and instruments referred to herein, constitutes the entire agreement and supersedes all other prior agreements and undertakings, both written and oral, among the parties, or any of them, with respect to the subject matter hereof.

IN WITNESS WHEREOF, Holdco, Mergeco and the Company have caused this Agreement to be executed as of the date first written above by their respective officers thereunto duly authorized.

HALLIBURTON COMPANY

By: Lester L. Coleman
Name: Lester L. Coleman
Title: Executive Vice President and General Counsel

HALLIBURTON HOLD CO.

By: Robert M. Kennedy
Name: Robert M. Kennedy
Title: Vice President

HALLIBURTON MERGE CO.

By: Robert M. Kennedy
Name: Robert M. Kennedy
Title: Vice President

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I, Susan S. Keith, Vice President and Secretary of Halliburton Company do hereby certify that the Board of Directors of Halliburton Company has approved and adopted this Agreement by duly authorized written consent dated December 5, 1996.

Susan S. Keith
Vice President and Secretary

I, Susan S. Keith, Vice President and Secretary of Halliburton Hold Co. do hereby certify that the Board of Directors of Halliburton Hold Co. has approved and adopted this Agreement by duly authorized written consent dated December 5, 1996.

Susan S. Keith
Vice President and Secretary

I, Susan S. Keith, Vice President and Secretary of Halliburton Merge Co. do hereby certify that the Board of Directors of Halliburton Merge Co. has approved and adopted this Agreement by duly authorized written consent dated December 5, 1996.

Susan S. Keith
Vice President and Secretary

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The undersigned, Susan S. Keith, does hereby certify that she is the duly elected and currently acting Secretary of Halliburton Merge Co., a Delaware corporation and one of the constituent corporations to the Merger (as hereinafter defined), and she does hereby further certify (i) that the Agreement and Plan of Reorganization dated as of December 11, 1996 among Halliburton Company, a Delaware corporation, Halliburton Hold Co., a Delaware corporation, and Halliburton Merge Co. (the "Merger Agreement"), attached to this Certificate of Merger and providing for the merger (the "Merger") of Halliburton Merge Co. with and into Halliburton Company pursuant to Section 251(g) of the General Corporation Law of the State of Delaware, was duly adopted by Halliburton Merge Co. by action of its board of directors and without any vote of stockholders pursuant to the said Section 251(g) and (ii) that the conditions specified in the first sentence of the said Section 251(g) have been satisfied.

Susan S. Keith
Secretary
Halliburton Merge Co.

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CERTIFICATE

Pursuant to Section 251(g) of the
General Corporation Law of the State of Delaware

Agreement and Plan of Reorganization

dated as of December 11, 1996 among

Halliburton Company, Halliburton Hold Co.

and Halliburton Merge Co.

This Certificate of Meger shall be effective at 11:30 a.m., Eastern Standard Time, on December 12, 1996.

Halliburton Company

The undersigned, Susan S. Keith, does hereby certify that she is the duly elected and currently acting Secretary of Halliburton Company, a Delaware corporation and one of the constituent corporations to the Merger (as hereinafter defined), and she does hereby further certify (i) that the Agreement and Plan of Reorganization dated as of December 11, 1996 among Halliburton Company, Halliburton Hold Co., a Delaware corporation, and Halliburton Merge Co., a Delaware corporation (the "Merger Agreement"), attached to this Certificate of Merger and providing for the merger (the "Merger") of Halliburton Merge Co. with and into Halliburton Company pursuant to Section 251(g) of the General Corporation Law of the State of Delaware, was duly adopted by Halliburton Company by action of its board of directors and without any vote of stockholders pursuant to the said Section 251(g) and (ii) that the conditions specified in the first sentence of the said Section 251(g) have been satisfied.

Susan S. Keith
Secretary
Halliburton Company

Halliburton Merge Co.

UNITED STATES DISTRICT COURT
FOR THE NORTHERN DISTRICT OF TEXAS
DALLAS DIVISION

HALLIBURTON ENERGY SERVICES, INC., Plaintiff, v. WEATHERFORD INTERNATIONAL, INC., and BJ SERVICES COMPANY, Defendants.	§ § § § § § § § § § § § §	Civil Action No. __________

DECLARATION OF WESLEY JAY BURRIS, II

Introduction

1. My name is Jay Burris. I reside in Denton County, Texas. I am over the age of 21 years, and I am competent to make this Declaration. I graduated from Oklahoma State University in 1981 with a Bachelor of Science degree.

2. In 1981, I was hired by Halliburton as a Design Engineer. I have been employed by Halliburton continuously since then. My current title is Product Manager for Tools and Testing which includes the Halliburton "FAS Drill" well tools and services. I am currently working out of one of Halliburton's offices in Dallas County, Texas. My office address is 2601 E. Belt Line Rd., Carrolton, Texas 75006.

3. Halliburton's "FAS Drill" products are well tools that are installed in the well bore at a downhole location and removed by drilling them out of the well.

Background

4. The goal of drilling a downhole tool out of the well bore of an oil and gas well is to drill the tool into small bits and chips that can be circulated (flushed) out of the well bore. Prior to the introduction of Halliburton's "FAS Drill" tools, drillable bridge plugs being used in oil and gas wells had a central mandrel and other major components made of metallic materials. These components were made of cast iron so that drilling out these tools required heavy drilling equipment, special drilling bits, and long drilling times, which was a costly operation that prevented their use in many applications.

Halliburton's "FAS Drill" Composite Bridge Plug and Frac Plug

5. Since January 2001, I have been the Product Manager for Halliburton's "FAS Drill" products. Since 1994, I had experience in sales and managing operations for the "FAS Drill" product line. I am familiar with the product line's history, development, marketing, market acceptance, and competitors. I receive internal Halliburton reports on sales, revenue, marketing, and progress of the "FAS Drill" product line. I review and analyze these types of reports on at least a quarterly basis. I regularly talk to personnel in the field, including sales representatives, service representatives, technical advisors, and customers, and I attend various oil-and-gas industry tradeshows.

6. The design of Halliburton's "FAS Drill" tools was the product of a significant investment in research and development by Halliburton that began in the late 1980's and extended into the early 1990s. The "FAS Drill" tools are designed to be made of easily drillable, non-metallic materials such as resin-based composite. The central body or mandrel of Halliburton's "FAS Drill" tools is made of non-metallic, resin-based composite material. Other

major components of the slip assemblies, such as the cone (also commonly referred to as the "wedge") are made of non-metallic, resin-based composite material. In some of these tools, the slips of the slip assemblies are made of a non-metallic, resin-based composite material. The "FAS Drill" tools replaced conventional metallic drillable service tools that had metallic bodies that required large drilling rigs and hours or even days to drill out of the well. The ability of the "FAS Drill" tools to be quickly drilled out results in great savings in drilling rig time and cost.

7. Halliburton introduced the first of its "FAS Drill" tools in 1994. Halliburton initially came out with a "Standard" "FAS Drill" product line, which included a composite bridge plug that is rated for use at up to 250°F and up to 5,000 pounds per inch differential pressure from above (psi). This "Standard" "FAS Drill" tool has both a center mandrel made of a non-metallic composite material and slips made of a non-metallic composite material.

8. In 1996, Halliburton added to the "FAS Drill" product line by introducing an "HPHT" bridge plug for use in high-temperature, high-pressure applications that is rated for use up to 350°F and up to 10,000 pounds per square inch (psi) differential pressure from above. This tool has a center mandrel made of non-metallic composite material, but the slips are made of a metallic material.

9. In 1998, Halliburton again added to the "FAS Drill" product line and introduced a special type of bridge plug called a "frac plug". Halliburton's frac plug had a composite center mandrel and a valve mechanism for allowing one-way fluid flow through the tool plug from below but preventing fluid flow in the opposite direction. Such a valve mechanism is usually either a check valve or a ball and seat. This design was particularly convenient for "multi-stage" well-completion procedures.

10. Halliburton's "FAS Drill" product line currently includes both bridge plugs and frac plugs, each of these downhole tools is offered in a size for use in 4½" and 5½" outer-diameter casing, and each is offered in "Standard" and "HT/HP" models.

Halliburton's "FAS Drill" Market

11. Since the introduction of the "FAS Drill" product line, Halliburton has created and distributed literature for the "FAS Drill" tools. True and correct samples of Halliburton's "FAS Drill" product sheets currently given to the trade are attached as Exhibit "A", document numbers H001038-43.

12. Halliburton's market for the drillable "FAS Drill" tools includes not only sales of the "FAS Drill" tools themselves, but also related services such as installing a tool in the well bore, well-completion services performed after installation of the tool (such as perforating, fracturing, acidizing, cementing, testing, etc.), and plug-removal services to drill the tool out of the well bore.

13. In some instances, Halliburton will sell a tool for the customer's use without associated well-completion services in order to keep a customer or meet a specific need. In cases such as these, Halliburton was able to obtain a higher premium for the plug to compensate for the lost sale of the related services.

14. Customer demand for the "FAS Drill" tools provided Halliburton a substantial advantage in marketing tools and related services over competitors' products and services that did not employ the new technology. Since 1994, Halliburton has sold tens of millions of dollars of the "FAS Drill" drillable well tools and related services.

15. "FAS Drill" tools opened new markets for drillable tools in multi-stage well fracturing completions. In these applications, "FAS Drill" composite frac plugs are installed between horizontally spaced producing formation zones to allow separate completion for each zone in the well. Halliburton then will service the well by using a wire line truck to lower a perforating gun into the well to perforate (shoot holes in) the casing in the lowest producing zone. To treat this zone, Halliburton pumps production enhancing treating liquids and solids into the open formation. After the lowest formation is treated, Halliburton uses a wire line truck to lower and install a "FAS Drill" frac plug to protect and isolate the lower formation. The next higher formation is perforated and treated, and a frac plug set above it. This process is repeated until all the desired formations have been treated. Due to the easy drilling characteristics of the "FAS Drill" tools, light drilling equipment such as a coil tubing rig can be used to drill all of the frac plugs out of the well in a short period.

Weatherford's "FracGuard" Composite Bridge Plugs and Frac Plugs

16. Weatherford International, Inc. is a major suppler of a wide range of downhole tools, including drillable packers and bridge plugs. Before 2001, Weatherford offered drillable well tools having cast iron components, however, its drillable tools did not offer the ease of drilling advantages and were not competitive with Halliburton's "FAS Drill" tools. According to its website, Weatherford also continues to offer its cast iron plugs for sale today. See, for example, a copy of Weatherford's public internet website page showing a listing of its "Packer Systems," a true and correct copy of which is attached as Exhibit "B", document numbers W000005-6)

17. In the summer of 2001, Halliburton's employees heard marketplace rumors that Weatherford was about to begin marketing and offering for sale a drillable bridge plug with

composite components. The products that Weatherford came out with were marketed as the "FracGuard Series Composite Bridge Plug" and "Frac Guard Series Composite Frac Plug."

18. I have reviewed Weatherford's public internet website in an effort to obtain further information about the "FracGuard" product, including Weatherford's publicized data sheets and promotional materials regarding its "FracGuard" product line. These Weatherford materials show that Weatherford is offering "FracGuard" tools that appear to provide design features and advantages and are directly competitive with Halliburton's "FAS Drill" tools.

BJ's Composite Bridge Plug

19. BJ Services Company is a relative new comer to the business of supplying a wide range of downhole tools. BJ has traditionally been known as primarily a contractor for well services to the oil and gas industry. Before 2001, BJ offered drillable well tools having cast iron components, however, its drillable tools did not offer the same advantages and were not competitive with Halliburton's "FAS Drill" tools. According to its website, BJ continues to offer its cast iron plugs for sale today. See, for example, a copy of BJ's public internet website page showing a listing of BJ's "Service Tools," a true and correct copy of which is attached as Exhibit "C", document number BJ000026.

20. In the summer of 2001, Halliburton heard marketplace rumors that BJ was about to begin marketing a drillable bridge plug with non-metallic components. The products that BJ came out with were marketed as "BJ's 'Python' Drillable Composite Bridge Plug."

21. In an effort to obtain further information about its "Python" products, I reviewed BJ's public internet website, including BJ's publicized data sheets and promotional materials regarding its "Python" products, and I reviewed a Power Point presentation distributed in the

trade by BJ. A true and correct copy of the slides from the Power Point presentation distributed in the trade by BJ relating to BJ's "Python" composite bridge plug is attached as Exhibit "D", document numbers BJ000004-25.

22. BJ's sales materials show that BJ is offering a "Python" tool that is sized for use in 4½" outer-diameter casing at up to 350°F and up to 10,000 pounds per square inch (psi) differential pressure that is directly competitive with at least one of Halliburton's "FAS Drill" bridge plugs, specifically Halliburton's "FAS Drill" bridge plug sized for use in a 4½" outer-diameter casing, the "HPHT" model for high temperature, high pressure applications rated for use at up to of 350°F and up to 10,000 pounds per square inch (psi) differential pressure. This model is also competitive with Halliburton's "FAS Drill" bridge plug sized for use in a 4½" outer-diameter casing, the "Standard" model described above.

23. Based on my review of these BJ sales materials, BJ is offering "Python" tools that appear to provide the same design features and advantages and are directly competitive with Halliburton's "FAS Drill" tools.

Harm to Halliburton and the "FAS Drill" Market

24. Halliburton's sales representatives report that Weatherford and BJ have attacked and continue to attack Halliburton's domestic market for "FAS Drill" drillable bridge plugs and frac plugs, including its market for related products and services. Weatherford has sold and continues to sell its "FracGuard" drillable tools and supervises their installation in wells. BJ sells its "Python" tools and performs the related well services.

25. Weatherford and BJ have marketed and continue to market their respective "FracGuard" and "Python" composite tools at substantially lower prices than Halliburton was

marketing its "FAS Drill" tools prior to their entry into the drillable tool market. The same potential customer will often solicit bids from both Halliburton and one or both of Weatherford and BJ.

26. Weatherford's and BJ's marketing and selling of their "FracGuard" and "Python" products is causing Halliburton to experience millions of dollars of lost sales within the United States of its "FAS Drill" bridge plugs and frac plugs to Weatherford's and BJ's lower-priced products.

27. Halliburton's markets within the United States have since experienced such price pressures from competitive offers of Weatherford's "FracGuard" and BJ's "Python" composite tools that Halliburton has been forced to increase its offered discounts up to about 50% and more off its list pricing in an effort to continue to sell its "FAS Drill" tools. Halliburton's profit margins on its "FAS Drill" product line are being eroded quickly.

28. Halliburton expects it will face extreme opposition from its customers to any future attempts to raise prices. After enjoying lower prices for Weatherford's and BJ's products, requiring customers to pay higher prices is not a realistic business option. Consequently, these price discounts may never be reversed. Halliburton has suffered an adverse impact on its market share and pricing structure that can never be quantified fully in dollars.

29. Halliburton has lost and continues to lose customer goodwill due to the pricing differences between Halliburton's "FAS Drill" tools and the Weatherford's and BJ's lower-priced products.

30. The presence of Weatherford's and BJ's competing products is eroding Halliburton's market share of drillable tools. Customers currently negotiate prices down due to the availability

of competing products at substantially lower prices. Weatherford and BJ have continued to offer tools at discounted prices relative to Halliburton's already steeply suppressed prices.

31. For example, in October 2001, a Halliburton technical advisor in the field advised Halliburton that in one case a customer was going to buy a Weatherford "FracGuard" composite frac plug, 4½" diameter size, standard model priced at $4,500 instead of Halliburton's "FAS Drill" offered to the customer for $5,200 (discounted 42% off Halliburton's list price for that tool of $9,009). Halliburton lost this job.

32. Also in October 2001, Halliburton heard in the market that Weatherford was offering to potential customers a first plug free. This is a direct attack on Halliburton's market share. Halliburton simply cannot compete to maintain market share on a pricing basis of "free."

33. In another recent example, on or about April 16, 2002, Halliburton bid to provide its "FAS Drill" composite frac plugs with well-completion services for a well operator managing a project in Wyoming having 22 wells, each well to require two or three plugs, in quantity of 22-33 composite plugs in the 4½" size. In an effort to meet the current competition, Halliburton bid $3,444.30/plug (discounted 70% off Halliburton's list price for the tool of $11,481 for an HPHT model). Halliburton still lost the bid to Weatherford. Halliburton has heard in the market that Weatherford has made a similar bid to another operator of $3,187.50/plug in quantity of 20-50 for its corresponding 4½" size "FracGuard" composite frac plug, which undercuts Halliburton's already steeply discounted pricing.

34. Typically, customers in the oil field industry prefer to obtain products and related services from the same company. Weatherford's and BJ's sales of products compete with Halliburton's "FAS Drill" products depriving Halliburton not only of sales, but also other profitable sales resulting from ongoing customer relationships. Customers develop and maintain

relationships with suppliers such that, if a customer chooses to use competing products, it may develop a permanent relationship with a competitor, thereby depriving Halliburton of market position for other products and services.

35. Halliburton's inventions opened up the multi-stage frac market to drillable tools and created an entirely new major market for Halliburton's drillable tools and related services. Over the next few years, operators of newly-drilled wells will select service companies to perform well-completion services, and the operators will select the service companies based on their ability to supply composite drillable bridge plugs and frac plugs. Weatherford and BJ will use their "FracGurad" and "Python" composite tools to create customer relationships that would have been Halliburton's.

36. Weatherford's and BJ's sales of competitive products to Halliburton's "FAS Drill" products adversely affects sales of Halliburton's related products and services. Due to Weatherford's and BJ's marketing and sales of their "FracGuard" and "Python" tools, Halliburton has experienced a decline in the sale of products and well services that relate to the use of a drillable composite bridge plug or frac plug tool. For example, Halliburton has seen a sharp decline in sales of well-treatment fluids, proppants, well perforation equipment, analysis services, electric-line services, and coil-tubing services to set and remove the plug, which Halliburton often sells to its customers in conjunction with a "FAS Drill" tool sale.

37. As of today's date, Halliburton is in the process of reducing its operations in certain domestic drillable tool markets. Weatherford's and BJ's marketing campaigns and predatory pricing are contributing to Halliburton's plans to institute layoffs of well-servicing employees, and it anticipates further layoffs and restructuring. When the market returns to a growth phase, employees like these and their experience will be difficult to replace.

38. If Weatherford and BJ are allowed to continue marketing their "FracGuard" and "Python" products, I believe Halliburton's prices for its "FAS Drill" products will continue to be undercut, Halliburton will continue to lose market share for drillable tools, Halliburton will continue to lose sales of collateral products and services, and Halliburton will continue to lose goodwill in the market. Halliburton may never be able to recover its pricing structure. And I believe these losses would be difficult or impossible to quantify.

39. If Weatherford and BJ were enjoined from selling their "FracGuard" and "Python" products having the mandrel and other major components made of non-metallic, composite materials, as used in Halliburton's "FAS Drill" tools, I believe that other downhole tool manufacturers and well-service providers would be discouraged from marketing, selling, and using such downhole tools, which would prevent further harm to Halliburton's market for its "FAS Drill" tools.

40. All statements made in this Declaration made on personal knowledge are true and correct and are based upon information learned in the course and scope of my employment with Halliburton. This Declaration is made with knowledge that willful false statements made herein are punishable by fine and/or imprisonment under 18 U.S.C. 1001.

FURTHER DECLARANT SAYETH NOT.

Wesley Jay Burris, II

6/13/02

Date

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FAS DRILL® Frac Plug

Used similarly to the FAS DRILL® Bridge Plug, FAS DRILL Frac Plugs are available in standard and high-pressure/high-temperature (HPHT) models.

Specific setting kits are used for each tool. Operations are identical for both versions, but standard Frac Plugs having operational limits of 250°F and 5,000 psi differential from above. HPHT models have operational limits of 350°F and 10,000 psi diffential from above.

Features and Benefits

- consists of composites and a packer set, giving it minimal metal content
- provides zonal isolation during multizone stimulation treatments
- holds differential pressure from above
- allows flow back from below plug
- saves rig time and reduces casing damage caused by long drillout processes
- drills out with conventional tri-cone or with junk-mill bits
- lower pin design prevents plug-off
- ball can be run in place or dropped from surface

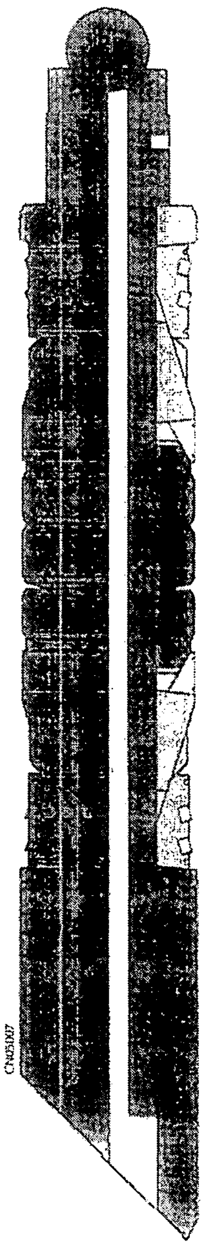
Operation

The FAS DRILL Frac Plug is designed to be set on Advanced® Slickline using the Downhole Power Unit (DPU®) or electric wireline. An adapter kit is required for setting tools.

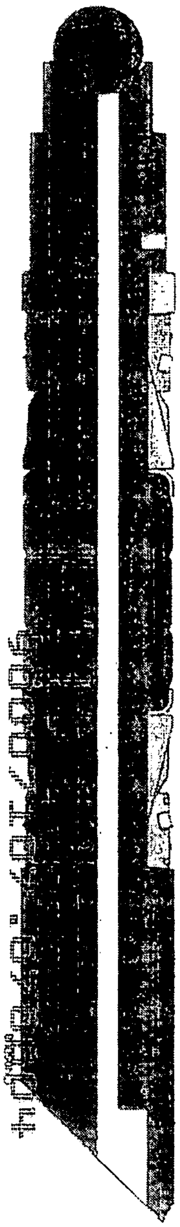
Setting Procedures

Operators can use one of the following types of equipment to set FAS DRILL Frac Plugs:

- electric wireline setting tools
- slickline setting tools
- coiled tubing setting tools



FAS DRILL®
Frac Plug



HPHT FAS DRILL® Frac Plug

FAS DRILL® Frac Plug Specifications

Part Number and Tool Size	Frac Plug Type	Casing		Dimensional Data			
		Size in.	Weight lb/ft	Maximum Casing ID in. (mm)	Minimum Casing ID in. (mm)	Maximum OD in. (mm)	Length in. (mm)
803.94530 100013809 (4 ½ in.)	Standard	4 ½	9.50 - 13.50	4.09 (103.9)	3.92 (99.6)	3.66 (93.0)	28.62 (726.9)
803.95510 100073960 (5 ½ in.)	Standard	5 ½	15.50 - 23.00	4.95 (125.7)	4.67 (118.6)	4.37 (111.0)	29.09 (738.9)
803.94535 101203305 (4 ½ in.)	HPHT	4 ½	9.50 - 13.50	4.09 (103.9)	3.92 (99.6)	3.66 (93.0)	27.92 (709.2)
803.95535 101203594 (5 ½ in.)	HPHT	5 ½	15.50 - 23.00	4.95 (125.7)	4.67 (118.6)	4.37 (111.0)	29.87 (758.7)

FAS DRILL® Frac Plug Temperature/Pressure Specifications

Tool Description	Maximum Recommended Temperature °F (°C)	Maximum Recommended Pressure from Above Psi (kPa)
4 ½-in. Frac Plug	50 - 250 (10 - 121)	5,000 (34 474)
5 ½-in. Frac Plug	50 - 250 (10 - 121)	5,000 (34 474)
4 ½-in. HPHT Frac Plug	50 - 350 (10 - 177)	10,000 (68 947)
5 ½-in. HPHT Frac Plug	50 - 350 (10 - 177)	10,000 (68 947)

FAS DRILL® Frac Plug Setting Kit Adapters*

Plug Size	Baker 20 Setting Kit	Baker 10 Setting Kit	HES 3 ½-in (GO) Setting Kit
4 ½-in. Standard		803.94540 101205730	803.94570 100073953
5 ½-in. Standard	803.95540 101204053		803.95580 101205733
4 ½-in. HPHT		803.94540 101205730	803.94570 100073953
5 ½-in. HPHT		803.94540 101205730	803.94570 100073953

* All of the above kits can be used for running the frac ball in place.

HALLIBURTON®

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FAS DRILL® Squeeze Packers and Sliding Valve Packers

FAS DRILL® Squeeze Packers

The FAS DRILL® Squeeze Packer has a one-way poppet-valve cement retainer that checks backflow and pressure from below the packer after remedial cementing operations. Designed for use at temperatures ranging from 50 to 250°F, the packer has minimal ferrous metal content, which allows for easy drillout. The poppet does not restrict fluid movement through the packer from above.

FAS DRILL® Sliding-Valve Packers

The FAS DRILL® Sliding-Valve Packer has a stinger-operated sliding valve that holds pressure from both directions. The sliding valve is opened and closed with workstring manipulation. When weight is placed on the set packer, the sliding valve opens. When pipe weight is lifted from the packer and the stinger is removed from the packer bore, the sliding valve closes, which isolates cement below the packer from the pressure and fluid above the packer.

Features and Benefits

FAS DRILL® Squeeze Packers and FAS DRILL® Sliding-Valve Packers have the following features and benefits:

- Each tool consists of composites and a packer set, with only minimal ferrous metal content.
- Both packers can be drilled out with conventional tricone or junk-mill bits.
- Both packers can function as cement retainers in squeeze cementing operations on land-based or offshore rigs, in vertical or deviated wells.
- The composite packer design reduces drillout time, resulting in shorter rig times and less likelihood of casing damage.

Operation

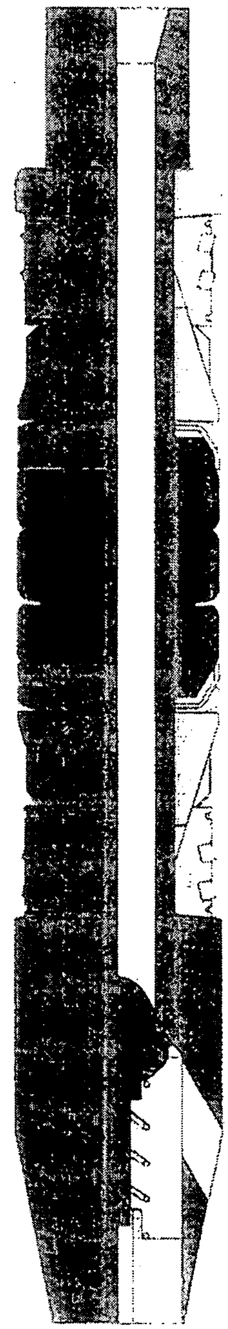
During operation, the packer operating mandrel (stinger) is inserted into the packer bore, where it seals the workstring and distributes weight to the slips and packer rubbers. The maximum allowable pipe weight is then set on the packer for a tighter fit.

During operation, hydraulic forces can add or subtract weight on the packer. Before using the packer, operators should complete hydraulic calculations to prevent overloading or pumpout.

Setting and Operating Procedures

Operators can use one of the following types of equipment to set and operate FAS DRILL® Packers.

- electric wireline setting tools
- slickline setting tools
- coiled tubing setting tools
- mechanical setting tools



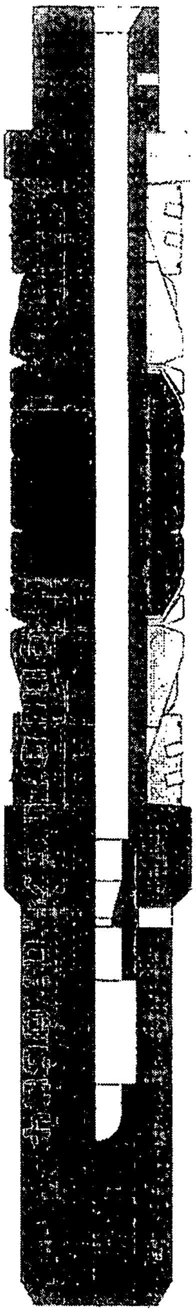
FAS DRILL® Squeeze Packer

FAS DRILL® Squeeze Packer Specifications

Part Number and Tool Size	Packer Type	Casing Size in.	Casing Weight lb/ft	Dimensional Data: Maximum Casing ID in. (mm)	Dimensional Data: Minimum Casing ID in. (mm)	Dimensional Data: Maximum OD in. (mm)	Dimensional Data: Length in. (mm)
802.92875 (2 7/8 in.)	Poppet Squeeze	2 7/8	6.40-7.90	2.44 (62.0)	2.33 (59.2)	2.18 (55.4)	19.15 (486.4)
802.93500 (3 1/2 in.)	Poppet Squeeze	3 1/2	9.20-12.70	2.99 (75.9)	2.75 (69.9)	2.56 (65.0)	22.64 (575.1)
802.94500 (4 1/2 in.)	Poppet Squeeze	4 1/2	9.50-13.50	4.09 (103.9)	3.92 (99.6)	3.66 (93.0)	28.43 (722.1)
802.95500 (5 1/2 in.)	Poppet Squeeze	5 1/2	15.50-23.00	4.95 (125.7)	4.67 (118.6)	4.37 (111.0)	27.61 (701.3)
802.97000 (7-in. HW)	Poppet Squeeze	7	29.00-38.00	6.18 (157.0)	5.92 (150.4)	5.50 (139.7)	35.96 (913.4)
802.97010 (7 in.)	Poppet Squeeze	7	20.00-29.00	6.46 (164.1)	6.18 (157.0)	5.80 (147.3)	35.96 (913.4)
802.97100 (7-in. HW)	Sliding Valve	7	29.00-38.00	6.18 (157.0)	5.92 (150.4)	5.50 (139.7)	40.01 (1016.3)
802.97110 (7 in.)	Sliding Valve	7	20.00-29.00	6.46 (164.1)	6.18 (157.0)	5.80 (147.3)	40.01 (1016.3)
802.97625 (7 5/8 in.)	Sliding Valve	7 5/8	20.00-42.80	7.12 (180.8)	6.50 (165.1)	6.12 (155.4)	40.01 (1016.3)
802.99625 (9 5/8 in.)	Sliding Valve	9 5/8	29.30-70.30	9.06 (230.1)	8.20 (208.3)	7.75 (196.9)	50.01 (1270.3)
802.91338 (13 3/8 in.)	Sliding Valve	13 3/8	48.00-76.60	12.71 (322.8)	12.28 (311.9)	11.68 (296.7)	50.01 (1270.3)

FAS DRILL® Squeeze Packer Operation Specifications

Tool Description	Maximum Recommended Temperature °F (C°)	Maximum Pressure psi (kPa)	Maximum Weight lbm (kg)
2 7/8-in. Squeeze Packer	50-250 (10-121)	5,000 (34,470)	8,000 (3629)
3 1/2-in. Squeeze Packer	50-250 (10-121)	5,000 (34,470)	12,000 (5443)
4 1/2-in. Squeeze Packer	50-250 (10-121)	5,000 (34,470)	30,000 (13,608)
5 1/2-in. Squeeze Packer	50-250 (10-121)	5,000 (34,470)	30,000 (13,608)
7-in. HW Squeeze Packer	50-250 (10-121)	5,000 (34,470)	40,000 (18,144)
7-in. Squeeze Packer	50-250 (10-121)	5,000 (34,470)	40,000 (18,144)
7-in. HW Sliding Valve Packer	50-250 (10-121)	5,000 (34,470)	40,000 (18,144)
7-in. Sliding Valve Packer	50-250 (10-121)	5,000 (34,470)	40,000 (18,144)
7 5/8-in. Sliding Valve Packer	50-250 (10-121)	5,000 (34,470)	40,000 (18,144)
9 5/8-in. Sliding Valve Packer	50-250 (10-121)	5,000 (34,470)	50,000 (22,679)
13 3/8-in. Sliding Valve Packer	50-250 (10-121)	5,000 (34,470)	50,000 (22,679)



FAS DRILL® SV Packer

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FAS DRILL® Bridge Plugs

The FAS DRILL® Bridge Plug is used similarly to a conventional permanent bridge plug.

FAS DRILL® Bridge Plugs are available in standard and high-pressure/high-temperature (HPHT) models.

Setting equipment and operation are identical for both versions, but standard bridge plugs have operation limits of 250°F and 5,000 psi differential from either direction. HPHT models have operation limits of 350°F and 8,000 or 10,000 psi differential.

Features and Benefits

- consists of composites and a packer set, giving it minimal ferrous metal content
- provides zonal isolation during multizone stimulation treatments
- isolates a lower zone during squeeze cementing operations on land-based or offshore rigs, in vertical or deviated wells
- saves rig time and reduces casing damage caused by long drillout processes
- drills out with conventional tricone or with junk-mill bits

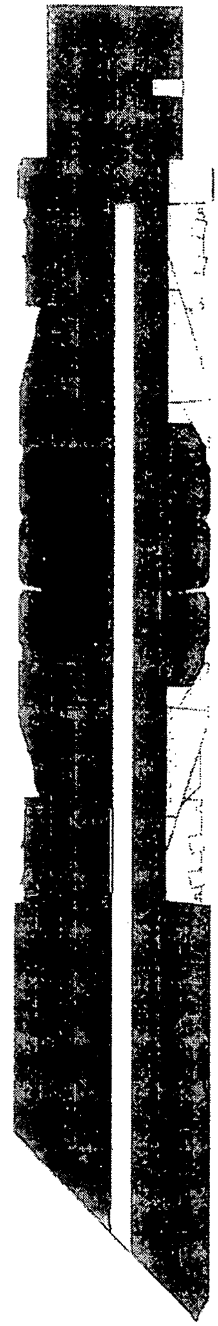
Operation

FAS DRILL® Bridge Plugs can be set on tubing, on drillpipe, or with conventional tools, such as electric wireline. An adapter kit is required for setting tools.

Setting Procedures

Operators can use one of the following types of equipment to set FAS DRILL® Bridge Plugs:

- electric wireline setting tools
- slickline setting tools
- coiled tubing setting tools
- mechanical setting tools



FAS DRILL®
Bridge Plug

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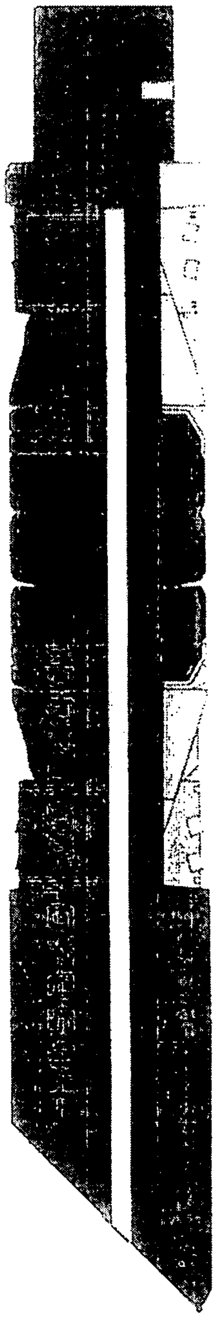
FAS DRILL® Bridge Plug Specifications

Part Number and Tool Size	Bridge Plug Type	Casing		Dimensional Data			
		Size in.	Weight lb/ft	Maximum Casing ID in. (mm)	Minimum Casing ID in. (mm)	Maximum OD in. (mm)	Length in. (mm)
803.92875 (2 7/8 in.)	Standard	2 7/8	6.40-7.90	2.44 (62.0)	2.33 (59.2)	2.18 (55.4)	18.00 (457.2)
803.94500 (4 1/2 in.)	Standard	4 1/2	9.50-13.50	4.09 (103.9)	3.92 (99.6)	3.66 (93.0)	28.92 (734.6)
803.95000 (5 in.)	Standard	5	11.50-18.00	4.56 (115.8)	4.27 (108.5)	3.97 (100.8)	29.00 (736.6)
803.95500 (5 1/2 in.)	Standard	5 1/2	15.50-23.00	4.95 (125.7)	4.67 (118.6)	4.37 (111.0)	29.09 (738.9)
803.97000 (7-in. HW)	Standard	7	29.00-38.00	6.18 (157.0)	5.92 (150.4)	5.50 (139.7)	35.15 (892.8)
803.97010 (7 in.)	Standard	7	20.00-29.00	6.46 (164.1)	6.18 (157.0)	5.80 (147.3)	35.30 (896.6)
803.97625 (7 5/8 in.)	Standard	7 5/8	20.00-42.80	7.12 (180.8)	6.50 (165.1)	6.12 (155.4)	35.09 (891.3)
803.99625 (9 5/8 in.)	Standard	9 5/8	29.30-70.30	9.06 (230.1)	8.20 (208.3)	7.75 (196.9)	46.59 (1183.4)
803.91338 (13 3/8 in.)	Standard	13 3/8	48.00-76.60	12.71 (322.8)	12.28 (311.9)	11.68 (296.7)	47.00 (1193.8)
803.93500 (3 1/2 in.)	HPHT	3 1/2	12.70*	2.75 (69.9)	2.75 (69.9)	2.56 (65.0)	22.58 (573.5)
803.94599 (4 1/2 in.)	HPHT	4 1/2	9.50-13.50	4.09 (103.9)	3.92 (99.6)	3.66 (93.0)	28.34 (719.8)
803.95599 (5 1/2 in.)	HPHT	5 1/2	16.50-23.00	4.95 (125.7)	4.67 (118.6)	4.37 (111.0)	28.39 (721.1)
803.97099 (7-in. HW)	HPHT	7	29.00-38.00	6.18 (157.0)	5.92 (150.4)	5.50 (139.7)	35.15 (892.8)



HPHT FAS DRILL® Bridge Plug

FAS DRILL® Bridge Plug Operation Specifications

Table 12.1—FAS DRILL® Bridge Plug Operation Specifications

Tool Description	Maximum Recommended Temperature °F (°C)	Maximum Recommended Pressure psi (kPa)
2 7/8-in. Bridge Plug	50-250 (10-121)	5,000 (34,474)
4 1/2-in. Bridge Plug	50-250 (10-121)	5,000 (34,474)
5-in. Bridge Plug	50-250 (10-121)	5,000 (34,474)
5 1/2-in. Bridge Plug	50-250 (10-121)	5,000 (34,474)
7-in. HW Bridge Plug	50-250 (10-121)	5,000 (34,474)
7-in. Bridge Plug	50-250 (10-121)	5,000 (34,474)
7 5/8-in. Bridge Plug	50-250 (10-121)	5,000 (34,474)
9 5/8-in. Bridge Plug	50-250 (10-121)	5,000 (34,474)
13 3/8-in. Bridge Plug	50-250 (10-121)	5,000 (34,474)
3 1/2-in. HPHT Bridge Plug*	50-350 (10-177)	10,000 (68,947)
4 1/2-in. HPHT Bridge Plug	50-350 (10-177)	8,000 (55,158)
5 1/2-in. HPHT Bridge Plug	50-350 (10-177)	8,000 (55,158)
7-in. HW HPHT Bridge Plug	50-350 (10-177)	8,000 (55,158)

*At 9.20 to 10.30 lb/ft, the recommended operation specifications for the 3 1/2-in HPHT Bridge Plug are 250°F (121°C) at 5,000 psi (34,474 kPa).

HALLIBURTON®

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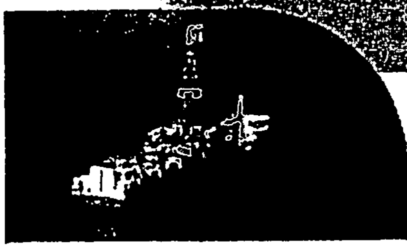
SEARCH

CORPORATE | PRODUCTS AND SERVICES | DIVISIONS | TECHNOLOGIES

Home > Products And Services : Completion > **Packer Systems**



COMPLETION

- Packer Systems
- Liner Systems
- Expandable Technologies
- Sand Control Systems
- Flow Control Systems
- Inflatable Packers
- Intelligent Well Systems
- Multilateral Systems
- Downhole Safety Valves
- Injection Systems
- Cementation Equipment
- Tubular Handling
- Gas Lift

PACKER SYSTEMS

Sealbore Packers |
Composite Plugs |
Hydraulic Packers |
Mechanical Packers |
Retrievable Packers |
Thru-tubing Packers |

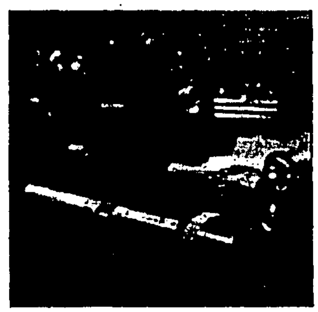
Accessories

Cement Retainers and Bridge Plugs |
Setting Equipment |
Well Maintenance |
Landing Nipples and Sleeves |
Anchor Catchers |

PACKER SYSTEMS AND COMPLETION ACCESSORIES

We continue to develop new products to meet the present and future needs of our customers, especially in high pressure/high temperature environments.

UltraPak™ Permanent Packer



The Weatherford UltraPak™ Permanent Packer is a robust, high-performance packer designed for high differential pressure to 10,000 psi, in single or multi-zone applications, in straight to highly-deviated wellbores. Performance Rating Envelopes have been developed for each size displaying combination loading from pressure and axial loads.

- Full envelope tested to ISO 14310 (V3)
- Tested in Q125 casing, API max & min ID
- Available with materials tailored for hostile environments
- Full strength, full circle slips
- Upper scoop head allows ease of stabbing seals in deviated wells
- Wireline or hydraulic setting options

FracGuard™ Composite Frac Plug

The FracGuard™ Composite Frac Plug provides a means to isolate a lower zone from an upper zone undergoing a high pressure stimulation. The integral check ball holds differential pressure from above but allows flow back from below the plug. The FracGuard plugs are available in standard and HP/HT versions. Both the standard

CONT.
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Variety
Innova
Service

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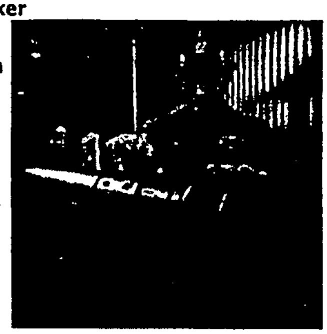
and HP/HT Frac Plugs can be run
on tubing, drill pipe, coiled tubing, or on wireline using conventional frac plug setting equipment.

- Holds full differential pressure from above and allows flow through the mandrel from below
- Multiple plugs may be run to isolate a series of zones
- Drills out quickly with conventional tri-cone or junk mill bits, saving time
- Beveled bottom prevents body from spinning, decreasing drill up times]
- Lightweight cuttings lift easily and minimize plugging of surface equipment

UltraPak™ HH Hydrostatic Packer



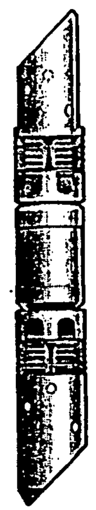
The Weatherford UltraPak™ HH hydraulic set permanent production packer has a hydrostatic setting feature that allows packer setting without intervention by eliminating need for wireline plugging devices. The UltraPak HH can be provided with a single seal bore, a dual bore with a larger upper bore for maximum possible ID, or with straight premium tubular connections.

- Based on proven packer design
- One piece mandrel throughout
- One Trip System eliminates need for intervention
- Metal back-up system expands to casing I.D. to prevent element extrusion
- Parts keyed for easy mill-out
- Elastomer options for harsh downhole environments
- Contingency conventional hydraulic setting feature

Terms and Conditions

Weatherford

Service Tools



BJ's ***"Python"***[TM] *Drillable Composite Bridge Plug*

BJ Services Company continues to expand its line of Service Tools. This means you have more options for getting top-quality tools.

BJ's new TST-3 service packer is our top of the line service tool rated to a differential of 10,000 psi, both above and below.

The enhanced tools selection now includes:

- Drillable Composite Bridge Plugs
- Service Packers
- Production Packers
- Retrievable Squeeze Tools
- Bridge Plugs
- Cement Retainers
- Fail Safe Surface Well Control Equipment
- Casing Scrapers

Products And Services

- **Tools**
  - Bridge Plugs
    - 2 3/8" to 8 5/8" Bridge Plugs
    - 3 1/2" to 13 3/8" Bridge Plugs
    - 3 1/2" to 20" Bridge Plugs
    - 4 1/2" to 5 3/4" Bridge Plugs
    - 4 1/2" to 7" Bridge Plugs
    - 9 5/8" to 20" Bridge Plugs
    - Composite Bridge Plug "Python"
    - Cup Type Retrievable Bridge Plugs
    - HE-HE2 WS Retrievable Bridge Plugs
    - Packer Type Retrievable Bridge Plug
  - Cement Retainers
  - Other
  - Production Packers
  - Service Packers

BJ employs some of the most qualified individuals in the industry. That means improved service for our customer base throughout the world.

Innovative technology in the hands of people who know how to use it for the best results in your well makes BJ Services the service provider you can trust —anywhere in the world. Contact BJ about your well today.

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Python™ *Composite Bridge Plug*

Presented by
Doug Lehr
BJ Services Company

BJ 4 1/2" Python™ Composite Plug

- Design Requirements
  - 350° F x 10,000 ΔP without cement on top
  - CT removal not to exceed 45 minutes
  - Design for 4-1/2" 9.5 - 15.1 ppf
  - Design for wire line conveyance
  - Avoid use of adhesives on part connections

BJ 4 1/2" Python™ Composite Plug

- Design Challenges
  - Reliable/fast removal
  - 350° F & 10,000 ΔP operation

BJ 4 1/2" Python™ Composite Plug

- How Did We "Rise to the Challenge"?
  - "Out of box thinking"
  - Novel slip design
  - Use of fiber-reinforced plastics - space age materials

BJ 4 1/2" Python™ Composite Plug

What was the Result?

Python™ Composite Bridge Plug

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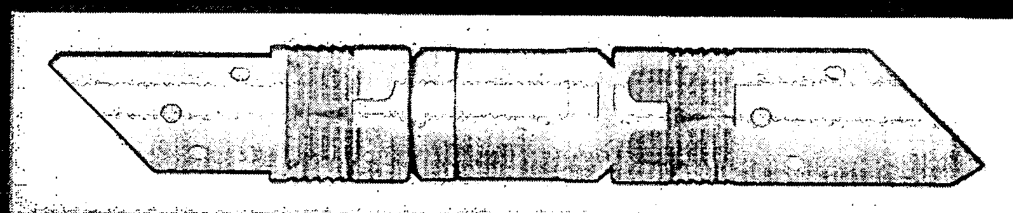
BJ 4 1/2" Python™ Composite Plug

- A Plug Designed for:
  - Reliable Drill Out
  - High Pressure Performance
  - Patent Pending



Due to its large size, the Video clip on the next slide is not available on this website. If you are interested in viewing this clip, please contact your local BJ Representative OR send us a request by clicking the GO BJ icon. In either case, please provide us the title of this presentation and the name(s) of the presenter(s).

BJ 4 1/2" Python™ Composite Plug

This Video clip is not available on the website

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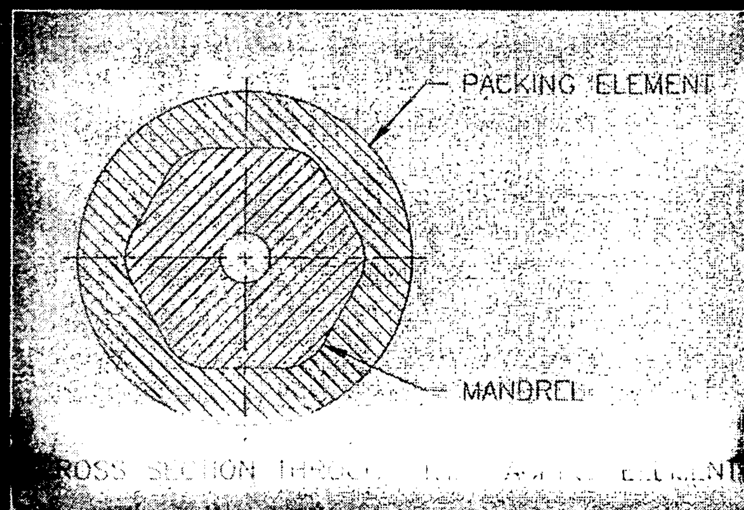
BJ 4 1/2" Python™ Composite Plug

- Materials of Construction
  - High temperature fiber reinforced plastics
  - Novel slip design - cast iron, hardened wickers - small pieces circulate out easily
  - HNBR elastomers, far longer lifetime vs traditional nitrile.
  - NO ADHESIVES USED TO CONNECT PARTS TOGETHER !

BJ 4 1/2" Python™ *Composite Plug*

Intrinsic rotational lock among all parts



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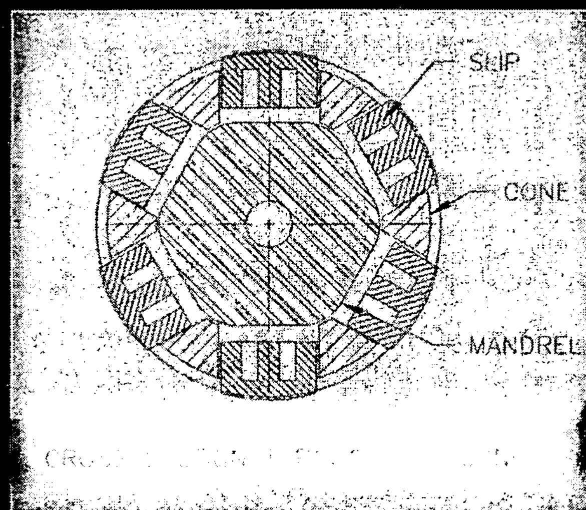
BJ 4 1/2" Python™ Composite Plug

- A Thoroughly Tested Product!
  - Over 40 Laboratory Tests
  - *1,500 man-hours of testing*

BJ 4 1/2" Python™ Composite Plug

Novel slip design, small pieces circulate out easily!

Slips are rotationally locked to the cone at all times



Use of internal voids in slips results in many small pieces during removal

BJ 4 1/2" Python™ Composite Plug

- Why 40 tests?
  - pressure
  - temperature
  - tension
  - setting tests, hydraulic and electric line
  - 3 sets of drill out tests

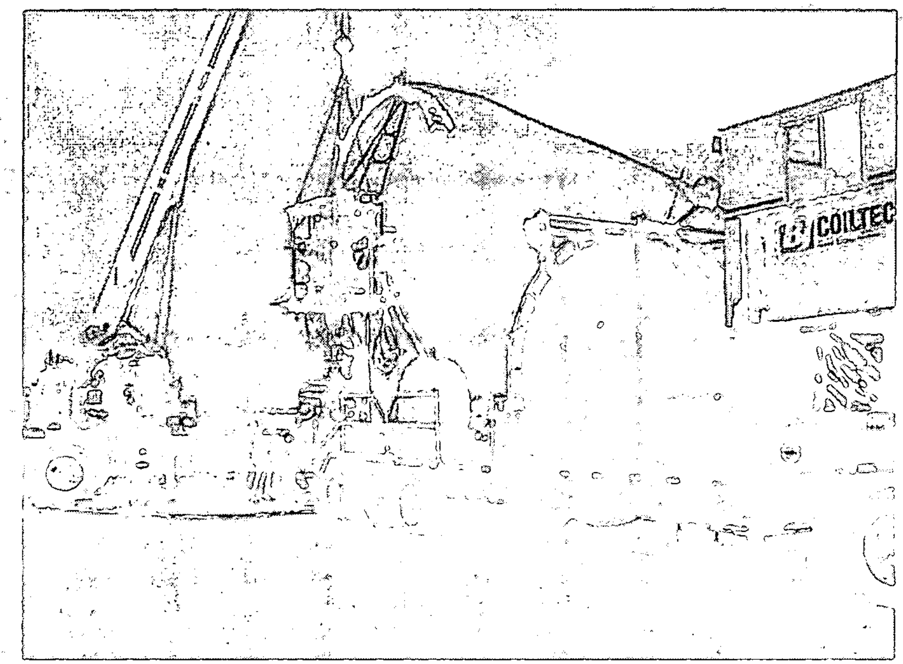
BJ 4 1/2" Python™ Composite Plug

- Full scale tests in 9.5 ppf -15.1 ppf
- Electric line tests in 9.5 ppf -15.1 ppf
- Most tests conducted at 350° F &10,000 ΔP
- 5 day "long term" test at 250° F & 5,000 ΔP
- Drop rate testing @ 300 foot per minute
- Release stud testing

BJ 4 1/2" Python™ Composite Plug

What about CT Removal?

4-1/2" Python™ Removal Testing



4-1/2" Python™ Removal Testing

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4-1/2" Python™ Removal Testing

- Summary of Simulated CT Mill Out tests:
  - – 5 blade carbide junk mill
  - – 2 BPM flow rate with fresh water
  - – virtually no WOB due to shallow depth
  - – 45 minutes for top plug
  - – 60 minutes for bottom plug
  - – Comprehensive mill out instructions available

BJ 4 1/2" Python™ Composite Plug

- Summary...
  - At 350° F, the Python far exceeds competitive temperature ratings
  - Cement NOT NEEDED to operate with integrity
  - CT Removal - very reliable due to intrinsically locked design - small pieces circulate out easily!
  - NO ADHESIVES USED TO CONNECT PARTS

Questions?

Python™
Composite Bridge Plug

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BJ000025

UNITED STATES DISTRICT COURT
FOR THE NORTHERN DISTRICT OF TEXAS
DALLAS DIVISION

HALLIBURTON ENERGY SERVICES, INC.,	§	
	§	
Plaintiff,	§	
	§	
v.	§	
	§	Civil Action No. ______________
	§	
WEATHERFORD INTERNATIONAL, INC.	§	
	§	
and	§	
	§	
BJ SERVICES COMPANY,	§	
	§	
Defendants.	§	

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DECLARATION OF HAROLD E. McGOWEN, III

Introduction

1. My name is Harold E. McGowen, III. I reside in Tyler, Texas. I am over the age of 21 years, and I am competent to make this Declaration.

2. I have a Bachelors of Science Degree in Mechanical Engineering from Texas A&M University, and I am a Registered Professional Engineer in the State of Texas. I have approximately 20 years experience applying reservoir, production, completion, and drilling technologies to enhance the profitability of oil and gas wells. Currently, I am the president and owner of Point-O-Five-Two, Inc., of Tyler, Texas, which provides expert consulting in oil-field services. A true and correct copy of my current resume is attached as Exhibit "A".

3. As described in more detail below, Weatherford International, Inc. ("Weatherford") is

marketing downhole well-service tools called the "FracGuard" composite bridge plug and composite frac plug. A frac plug is a type of bridge plug that allows flow from below and holds pressure from above through some mechanism such as a check valve.

4. As described in more detail below, BJ Services Company ("BJ") is marketing a downhole well-service tool called the "Python" composite bridge plug.

5. Both Weatherford's "FracGuard" and BJ's "Python" composite bridge-plug products are non-retrievable type downhole tools that are run into a well bore, set in the well to seal off the well bore, and then usually, after performing various well treatment procedures, the tool is drilled out of the well bore.

6. As described in more detail below, both Weatherford's "FracGuard" and BJ's "Python" tools are advertised and represented to have certain components made of a composite material (which is a non-metallic material), and both Weatherford and BJ advertise that their tools are easy to drill out.

7. Weatherford and BJ each had a sales booth at a major oil-and-gas industry tradeshow known as the 33rd Annual Offshore Technology Conference held May 6-9, 2002 at Reliant Hall in Houston, Texas (also known as "OTC 2002"). This is a tradeshow primarily focused on the fields of drilling, exploration, production, and environmental protection.

8. On May 7, 2002, at Halliburton's request, I attended the OTC 2002 tradeshow to visit Weatherford's and BJ's sales booths. My purpose was to view sample products on public display and observe the representations Weatherford and BJ are making to the public during their marketing of their respective "FracGuard" and "Python" composite bridge plugs.

Weatherford's "FracGuard" Composite Bridge Plug and Frac Plug

9. At Weatherford's booth in the OTC 2002 tradeshow, Weatherford was marketing its "FracGuard" composite bridge plug and frac plug. I talked to a person present in Weatherford's booth who wore a badge identifying himself as a representative of Weatherford. The representative showed me a physical example of a "FracGuard" composite bridge plug (or frac plug, which is a type of bridge plug), he described the tool to me, and he answered my questions regarding its structure, operation, and component materials. Also, I reviewed Weatherford's advertising on its website for the "FracGuard" composite bridge plug and frac plug

at http://www.weatherford.com/weatherford/groups/public/documents/general/wft000808.pdf

and

at http://www.weatherford.com/weatherford/groups/public/documents/general/wft000809.pdf,.

True and correct copies of these web pages are attached as Exhibit "B", document numbers W000001 and W000002.

10. Based on (a) the circumstances that I observed at Weatherford's booth, including the representations made to me by Weatherford's representative, and (b) the advertisements on Weatherford's website, I understood that Weatherford is marketing and offering for sale Weatherford's "FracGuard" composite bridge plug.

11. During my visit to Weatherford's booth at the OTC 2002, the Weatherford representative made certain representations to me about Weatherford's "FracGuard" composite bridge plugs, and I made certain observations about the physical example of the tool he showed to me, including the following:

a. The Weatherford representative confirmed that the "FracGuard" tool is a drillable type bridge plug that can be drilled out of the well bore quickly.

b. The Weatherford representative confirmed that Weatherford's "FracGuard" tool has a center mandrel made of a non-metallic material. He further confirmed that the center mandrel is made of a composite material. However, the Weatherford representative did not specify the type of composite material. On the display example of Weatherford's "FracGuard" tool, I observed that the center mandrel has a round cross-section.

c. I observed and the Weatherford representative confirmed that Weatherford's "FracGuard" tool has a packing element on the tool designed to seal with the well bore. Weatherford's web advertisement states that the "FracGuard" composite bridge plug and frac plug, the "standard" models "BP8" or "FP8", respectively, are designed to seal a well bore having 4½" or 5½" outside diameter casing at a temperature of up to 250°F and a differential pressure of up to 8,000 pounds per square inch (psi), whereas the "high temperature/high pressure" models "BP10" or "FP10", respectively, are designed to seal a well bore having 4½" or 5½" outside diameter casing at a temperature of up to 350°F and a differential pressure of up to 10,000 pounds per square inch (psi).

d. I observed that Weatherford's "FracGuard" tool has two slip assemblies so that, when the tool is in a set position, it can be self-supporting without any tubing string in the well bore. Each of these slip assemblies includes several slips, a cone for wedging the slips, and a support structure for the slips on the opposite side of the slips from the cone. The two slip assemblies are located above and below the packing element.

e. The Weatherford representative confirmed that the cone of both slip assemblies of Weatherford's "FracGuard" tool is made of a non-metallic material. He further

confirmed that the cone is made of a composite material. However, the Weatherford representative did not specify the type of composite material. The cone of Weatherford's "FracGuard" tool has a continuous, conically-shaped wedge surface around the cone for engaging the slips.

f. The Weatherford representative confirmed that the support structures of both slip assemblies in Weatherford's "FracGuard" tools are made of a non-metallic material. He further confirmed that the support structures are made of a composite material. However, the Weatherford representative did not specify the type of composite material.

12. On a copy of Weatherford's webpage advertisement for its "FracGuard" composite bridge plug, I have indicated the center mandrel, the packing element, and the upper and lower slips, cones, and support structures. This is attached as Exhibit "C", document number W000003.

BJ's "Python" Composite Bridge Plug

13. At BJ's booth in the OTC 2002 tradeshow, BJ was marketing its "Python" composite bridge plug. I talked to a person present in BJ's booth who wore a badge identifying himself as a representative of BJ. The representative showed me a physical example of a "Python" composite bridge plug or frac plug, he described the tool to me, and he answered my questions regarding its structure, operation, and component materials. Also, I reviewed BJ's advertising on its website for the "Python" composite bridge plug at http://www.bjservices.com/website/ps.nsf/0/6EB75879F653F39A86256A540001E93F/$file/BJ+Python+Composite+Bridge+Plug.pdf. A true and correct copy of BJ's web advertisement is attached as Exhibit "D", document number BJ000001.

14. Based on (a) the circumstances that I observed at BJ's booth, including the representations

made to me by the BJ representative, and (b) the advertisements on BJ's website, I understood that BJ is marketing and offering for sale the "Python" composite bridge plug.

15. During my visit to BJ's booth at the OTC 2002, the BJ representative made certain representations to me about BJ's "Python" composite bridge plug and I made certain observations about the physical example of the tool he showed to me, including the following:

a. The BJ representative confirmed that the "Python" tool is a drillable type bridge plug that can be drilled out of the well bore quickly.

b. The BJ representative confirmed that BJ's "Python" tool has a center mandrel made of a non-metallic material. He further confirmed that the center mandrel is made of a composite material. However, the BJ representative did not specify the type of composite material. In addition, I observed that the center mandrel is multi-sided. The BJ representative explained that the center mandrel was multi-sided to prevent the mandrel from spinning as it is being drilled out of the well bore.

c. I observed and the BJ representative confirmed that BJ's "Python" tool has a packing element on the tool designed to seal with the well bore. BJ's website advertisement states that the "Python" composite bridge plug is designed to seal a well bore having 4½" outside diameter casing at a temperature of up to 350°F and a differential pressure of up to 10,000 pounds per square inch (psi).

d. I observed that BJ's "Python" tool has two slip assemblies so that, when the tool is in a set position, it can be self-supporting without any tubing string in the well bore. Each of these slip assemblies includes several slips, a cone for wedging the slips, and a support structure for the slips on the opposite side of the slips from the cone. The two slip assemblies are located above and below the packing element.

e. The BJ representative confirmed that the cone of both slip assemblies in BJ's "Python" tool is made of a non-metallic material. He further confirmed that the cone is made of a composite material. However, the BJ representative did not specify the type of composite material. The cone of BJ's "Python" tool has several flat wedge surfaces arranged around its circumference for engaging the slips.

f. The BJ representative confirmed that the support structures of both slip assemblies in BJ's "Python" tool are made of a non-metallic material. He further confirmed that the support structures are made of a composite material. However, the BJ representative did not specify the type of composite material.

16. On a copy of BJ's website advertisement for its "Python" composite bridge plug, I have indicated the center mandrel, the packing element, and the upper and lower slips, cones, and support structures. This is attached as Exhibit "E", document number BJ000002.

17. All statements made in this Declaration based on personal knowledge are true. All statements made in this Declaration based upon information and belief are believed to be true. The expert opinions and statements that I offer in this Declaration are based upon information and data reasonably relied upon by other experts in the field to form opinions in this field. This Declaration is made with knowledge that willfully false statements made herein are punishable by fine and/or imprisonment under 18 U.S.C. § 1001.

FURTHER DECLARANT SAYETH NOT.

Harold E. McGowen

Harold E. McGowen, III

Date: 6/4/2002

3657 Woods Blvd. 903-566-2323
Tyler, Texas 75707 harold.mcgowen@point-o-five-two.com

Harold E. McGowen III, PE, PMP

Employment History

2001– Present **President, Point-O-Five-Two, Completion Diagnostics, Tyler, Texas**

- Recent projects include large scale fracturing fluid performance study on 1,000 Codell Niobrara refracs, litigation support on bridge plug failure case and bridge plug patent case, nodal analysis, school on natural gas field development and sand control design for high rate gas field.

1997 - 2001 **Senior VP of Engineering Services, Signa Engineering Corp., Houston, Texas**

- 3,100 hours project management for 60+ projects with budgets up to $100MM
- Projects included complex junction multilateral, hydraulic fracturing, dual-completions, environmental site assessment, and field development. Designed and debugged surface facilities, artificial lift systems and corrosion programs.
- Designed and implemented completion, stimulation, testing and logging programs.
- International projects in South America, Asia and Africa, onshore and offshore.

1992 - 1997 **President, NaviData Systems, Inc., Kingwood, Texas**

- Accumulated 3,000 hours project management experience on over 30 projects.
- Prepared environmental site assessments and/or SPCC plans for 2,000+ properties.
- Developed client/server databases for technical applications.

1988 - 1992 **Engineering Manager, Trinity Resources, Inc., Houston, Texas**

- Designed drilling, workover and stimulation programs and monitored over 220 properties.
- Evaluated properties for purchase, sale, farm-out/farm-in and invested multi-million dollar development budget. Averaged 40% rate of return.

1984 - 1988 **Petroleum Engineer, Union Pacific Resources Company, Houston, Texas**

- Improved profitability through optimizing the performance of 90 wells in five fields.
- Recommended, designed, and supervised drilling, workover, and completion operations.

1982 - 1983 **Engineering Technician, GEO-Vann, Inc., Katy, Texas**

- Participated in design, testing and manufacture of prototype down-hole tools.

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Education

1982 - 1983 **Bachelors of Science Degree in Mechanical Engineering, 1982**

- Texas A&M University, College Station, Texas

Training

1984 - 2000 **Summary of Industry Schools**

Project Management, Statistics, Site Assessment, Fetkovich Type Curves, Horizontal, Drill Stem Failure, Compressors, Reservoir, Nodal Analysis, Logging, Fracturing, Corrosion, Production Operations, Perforating, and Hydrogen Sulfide.

Summary of Capabilities

Twenty years experience applying reservoir, production, completion, and drilling technologies to enhance profitability. Tenacious problem-solver and dedicated team member. Versatile, self-motivated, innovative, analytical and conscientious. Strong written, verbal and interpersonal skills. Excellent instructor and public speaker. Expertise in project management, petroleum engineering, information systems, and business management.

Project Management

More than 6,000 hours experience in initiating, planning, controlling, and executing over 90 technical projects in the last eight years alone. Proven ability to manage technically difficult advanced scope projects with multimillion-dollar operations budgets.

Petroleum Engineering

Primary specialization is applied reservoir and production engineering. Expertise in corrosion, reserves projections, hydraulic fracturing, sand control, artificial lift, surface facilities, field development, underbalanced operations, and multilateral completions. In-depth knowledge of risk management, probabilistic economic analysis and prospect evaluation. Extensive experience in asset evaluation and environmental due diligence. International exposure includes: Colombia, Algeria, Venezuela, Mexico, Thailand, Indonesia and global reservoir research project. Domestic areas studied include: South Texas, Austin Chalk, Montana, Mississippi, San Juan Basin (Coal Bed Methane), Black Warrior, East Texas, GOM.

Information Technology

Pioneer in the application of information technology to engineering problems. Proficient with Windows 2000, Office 2000, Outlook, Project 2000, and Visio. Created complex programs in Fortran, Basic, FoxPro, and SQLWindows. Fluent in spreadsheets, databases, client/server, and SQL queries. Recent projects include writing Signa's client/server Independent Contractor Database in SQLWindows, development of the original version of Signa's web site in NetFusion and creation of a project tracking system in MS FoxPro.

Business Management

Hired, trained and supervised engineering, technical and clerical staff. Supervised and performed administrative tasks including land, regulatory, and accounting. Familiar with receivables, cash flow, profit and loss statements, budgeting, balance sheets, joint interest billing, operating agreements, and project accounting. Experienced with drafting and negotiating contracts. Heavy exposure to legal issues surrounding patents and environmental compliance.

Accreditations

Registered Professional Engineer in the State of Texas, 1989

Certified Project Management Professional, 2001

Professional Memberships

Society of Petroleum Engineers (SPE), 1984

Project Management Institute (PMI), 1998

American Association of Drilling Engineers (AADE), 2000

Publications

"Applicability of Underbalanced Drilling to Multilateral Junctions", Presented at IADC UBO Technology Conference, Houston, Texas, August 2000 (with George Medley)

"Fulfilling Technical, Educational Needs Key to UBO's Expansion", *The American Oil & Gas Reporter*, August 1999 (with co-authors)

"UBO Technology Expands Horizontal's Success", *The American Oil & Gas Reporter*, July 1999 (with co-authors)

"Risk Analysis", Chapter 9, Underbalanced Manual, Signa Engineering Corp., August 1998

"Development of an Integrated Petroleum Engineering and Geologic Information System", SPE 2441, Presented at SPE Annual Meeting, January 1994

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Detailed Employment History

2000 - 2001 **Signa Engineering Corp.** **Houston, Texas**

Senior VP of Engineering Services

Responsibilities include oversight of engineering group including sales proposals, resource allocation, training, customer satisfaction, status reports, and implementation of "best practices" project management. Variety of projects expanded knowledge, such as:

- Stimulation technology research to defend major service companies' hydraulic fracturing patents. Managed research assistants and provided opinion. Refined knowledge and expertise in controlling fines migration and hydraulic stimulation of coal bed methane and tight sands in the San Juan Basin of New Mexico.
- Completed 3-year research project related to complex junction multilateral technology. Became intimately familiar with the design/application of the major multilateral completion systems and the methodology for screening multilateral candidates. Identified formations and fields suitable for multilateral. Developed probabilistic damages model. Testified on damages model and prior art challenge of patents. Team consisted of geologists, reservoir engineers, drilling engineers, and support staff.
- Developed and taught schools on petroleum economics, risk analysis, project management and multilateral completions.

1998- 1999 **Signa Engineering Corp.** **Houston, Texas**

VP of Project Management

Provided engineering and project management on numerous projects, for example:

- Six well completion program in South Texas. Planned, executed, and managed project team. Challenges included H_2S, CO_2, hydraulic stimulation, dual completions, chrome tubulars, underbalanced perforating, etc. Profitable multi-well project ongoing through 2nd Qtr. 2000.
- Research for major service company. Established specifications for next generation underbalanced surface separation system. Activities included competitive benchmarking, needs analysis, requirements definition, research, and report preparation. Project completed on time, on budget and within the client's requirements.
- Evaluated Coastal's Austin Chalk acreage for multilateral recompletion.

1997 - 1998 **Signa Engineering Corp.** **Houston, Texas**

Manager of Reservoir, Production and Software Engineering

Provided a wide variety of reservoir, production and training services to Signa's clients and completed Signa's IPC database. Significant projects included:

- Lead team that designed horizontal completion for unconsolidated channel sand offshore Thailand. Evaluated numerous sand control designs. Activities included reservoir analysis, equipment evaluation, laboratory testing, nodal analysis, and casing design. This 25-well, $100 million (+/-) drilling project was successfully implemented in January of 1999.
- Environmental audit of brine contaminated aquifer on 15,000-acre ranch in West Texas.
- Performed a field development study and operational review for horizontal potential on three large Algerian oilfields. Made recommendations to client on methods to improve production and lower operating expenses. Team included production engineer, drilling engineer, petroleum engineer and a geologist.
- Created a complete field development plan for a new field discovery in Colombia, including volumetric reserves, water coning and horizontal well analysis. Team included geologist, petroleum engineer and Ph.D. reservoir engineer.

1992 - 1997	NaviData Systems, Inc.	Houston, Texas

President and Principal

- Supervised four (4) full time employees and five (5) subcontractors.
- Developed business plan, incorporated, raised capital, setup offices, hired employees and created marketing effort including brochures, trade shows and sales calls.
- Managed land, regulatory, joint interest accounting and production operations for small operator. Evaluated properties and estimated reserves for independents.
- Performed environmental site assessments on over five hundred (500) properties and prepared Spill Prevention Control and Countermeasure plans on over two thousand (2,000) properties for both independents and Fortune 500 companies.
- Through training and experience developed general background in environmental regulations and expertise in Phase I and Phase II environmental site assessments.
- Developed inspection/auditing software. Increased inspection efficiency 400%.
- Diversified into development of engineering software applications. Through staff and personal effort developed several engineering database applications for Fortune 500 oil and gas operators.
- Through personal study and mentoring from more experienced programmers, developed proficiency in object oriented programming, graphical user interface design, relational client/server databases, Structured Query Language (SQL), entity relationship diagrams, referential integrity, data synchronization and expert systems.
- Accumulated broad knowledge of software testing, requirements tracking, defect tracking and deployment tools.
- Negotiated merger with Signa Engineering Corp. that was finalized in April 1997.

1988 - 1992	Trinity Resources, Inc.	Houston, Texas

Engineering Manager

- Handled all engineering and operations for independent producer. Coordinated and managed activities of two (2) staff members and three (3) consultants.
- Chief architect of several profitable oil field deals. Became experienced in structuring deals and negotiating contracts with sophisticated terms such as due diligence, carries, back-ins and arbitration. Developed strategies to meet the company's long-term goals.
- Monitored the companies non-operated interest in over 200 properties; evaluated AFE Proposals for workover, re-entry, recompletion and horizontal drilling.
- Performed reserves projections on approximately 150 horizontal Austin Chalk wells and created a probability distribution to predict Horizontal performance.
- Evaluated over 1200 vertical Austin Chalk wells to determine post-stimulation performance increase. Develop model to predict stimulation performance.
- Constructed database and expert system to analyze 4300-well Giddings Austin Chalk field for re-stimulation, recompletion and horizontal potential. Processed well data, performed statistics, computer mapped performance data and derived expert rules to automate candidate selection.
- Based on expert system, developed, presented to Board, and implemented business plans to invest multi-million dollar budget. Averaged 40% rate of return.
- Evaluated numerous acquisitions and packaged over $10 million in divestitures. Advised management to reject low offers on major asset; ultimately received 200% of original offer.
- Assisted U.S. State Department related to NAFTA. Studied horizontal potential of Mexican oil fields. Identified Chicontepec for horizontal drilling. Accompanied U.S. representative to Mexico and met with PEMEX. Subsequent to meeting PEMEX experimented with Horizontal technology in the field.

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1984 - 1988	Union Pacific Resources Co.	Houston, Texas

Petroleum Engineer

- Initiated highly profitable $2.9 million re-stimulation project. Dramatically increased production and saved $250,000 over previous programs.
- Prepared reserves estimates and performed economic analysis on $10 million offshore project and presented recommendations to management.
- Created daily production reporting system for major field.
- Built oil field pipe and inventory control system for use in field office.
- Coordinated planning and execution of $3.5 million drilling program, saving $360,000.
- Supervised field operations for 90 wells in 5 fields. Evaluated major properties for development, exploration, purchase and sale.
- Performed reservoir analysis, planned and supervised completion of Taylor wildcat.
- Designed computerized corrosion monitoring system that reduced costs.
- Optimized design of artificial lift systems. Promoted computerized analysis of sucker rod pumping systems that was implemented and reduced rod breaks in 170 well field by 10%+.
- Evaluated multi-million dollar failure of SCSSV for critical offshore platform in Gulf of Mexico. Determined cause of mechanical failure and resulting complications in workover operations to repair wells. Made recommendations to management concerning proper SCSSV tool design, metallurgy and operating procedures.
- Designed and implemented gas plant revisions including separation and brine disposal.

1983	GEO-Vann, Inc.	Katy, Texas

Engineering Technician

- As part of pursuit of second degree in Industrial Engineering, sold Geo-Vann on starting a co-op program with Texas A&M.
- As a result of these efforts placed another student and myself in the companies' research and development center in Katy, Texas.
- Participated in design, testing and manufacture of prototype down-hole tools related to tubing conveyed perforating and explosives systems.
- Developed shear pin failure predictive computer model in Basic that was used to increase the accuracy of pressure actuation pressures for down-hole tools.
- Become familiar with down-hole tool design, including the use of differential pressure, latching mechanisms, and materials.
- Designed and built and electro-mechanical device for measuring the explosive force of primer cord.

Weatherford®
Completion Systems

FracGuard™ Series Composite Bridge Plug (BP8 and BP10)

The Weatherford FracGuard™ Composite Bridge Plug provides a means to temporarily plug a well or to isolate zones during high pressure stimulation. The composite body and component construction allow for rapid drill up using common workover type bits. The lightweight cuttings produced lift easily and do not pile up on plugs below in multiple plug applications.

The Weatherford FracGuard™ Composite Bridge Plugs are available in standard and High Pressure / High Temperature (HP/HT) versions. The **BP8** standard bridge plug is rated to 8,000 psi differential pressure from above up to 250°F and the BP10 HP/HT version is rated to 10,000 psi differential pressure from above at 350°F.

Both the Standard and the HP/HT Bridge Plugs may be run on tubing, drill pipe, coiled tubing, or on wireline using conventional bridge plug setting equipment.

Applications:

- Single or multiple zone stimulation
- Vertical, deviated, horizontal or multilateral wellbores
- Temporary well plugging
- Underbalanced, multiple zone completions

Features:

- Holds full differential pressure from above and below
- Multiple plugs may be run to isolate a series of zones
- Allows underbalanced drill out of multiple plugs which protects sensitive formations
- Drills out quickly with conventional tri-cone or junk-mill bits which saves time
- Beveled bottom prevents body from spinning which speeds drill up times
- Lightweight cuttings lift easily and minimize plugging of surface equipment

Specification Guide:

CASING				BRIDGE PLUG		
O.D. in/mm	*Weight* lb./ft	*Min. I.D.* in/mm	*Max. I.D.* in/mm	*Max. O.D.* in/mm	*Temperature Rating*, °F	*Pressure Rating*, psi
4-1/2 *114.30*	9.5 - [illegible]	3.920 *99.57*	4.090 *103.89*	3.660 *92.96*	250	8,000
	15.1 - [illegible]	3.754 *95.35*	3.826 *97.18*	3.595 *91.29*	250	8,000
5-1/2 *139.70*	15.5 - [illegible]	4.670 *118.62*	4.950 *125.73*	4.370 *[illegible]*	250	8,000

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www.weatherford.com

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Weatherford
Completion Systems

FracGuard™ Series Composite Frac Plug
(FP8 and FP10)

The Weatherford FracGuard™ Composite Frac Plug provides a means isolate a lower zone from an upper zone undergoing a high pressure stimulation. The integral check ball holds differential pressure from above but allows flow back from below the plug.

The Weatherford FracGuard™ Composite Frac Plugs are available in standard and High Pressure / High Temperature (HP/HT) versions. The FP8 standard bridge plug is rated to 8,000 psi differential pressure from above up to 250°F and the FP10 HP/HT version is rated to 10,000 psi differential pressure from above at 350°F.

Both the Standard and the HP/HT Frac Plugs can be run on tubing, drill pipe, coiled tubing, or on wireline using conventional bridge plug setting equipment.

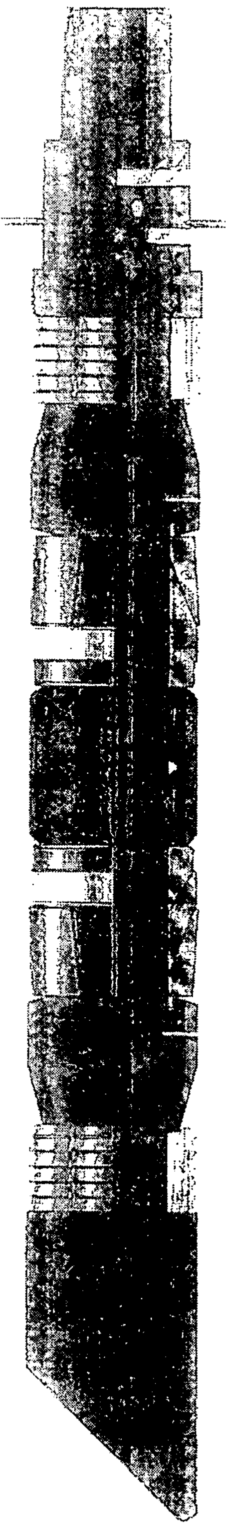
40907.07170006

Applications:

- Single or multiple zone stimulation
- Vertical, deviated, horizontal or multilateral wellbores
- Underbalanced, multiple zone completions

Features:

- Holds full differential pressure from above and allows flow through the mandrel from below
- Multiple plugs may be run to isolate a series of zones
- Drills out quickly with conventional tri-cone or junk-mill bits which saves time
- Beveled bottom prevents body from spinning which speeds drill up times
- Lightweight cuttings lift easily and minimize plugging of surface equipment
- Ball is pinned in place in the plug to eliminate possible seating problems associated with floating balls



Specification Guide:

CASING				BRIDGE PLUG		
O.D. in/mm	*Weight* lb./ft	*Min. I.D.* in/mm	*Max. I.D.* in/mm	*Max. O.D.* in/mm	*Temperature Rating*, °F	*Pressure Rating*, psi
4-1/2 *114.30*	9.5 - 1[illegible]	3.920 *99.57*	4.090 *103.89*	3.660 *92.96*	250	8,000
	15.1 - 1[illegible]	3.754 *95.35*	3.826 *97.18*	3.595 *91.29*	250	8,000
5-1/2 *139.70*	15.5 - 2[illegible]	4.670 *118.62*	4.950 *125.73*	4.370 *111.00*	250	8,000

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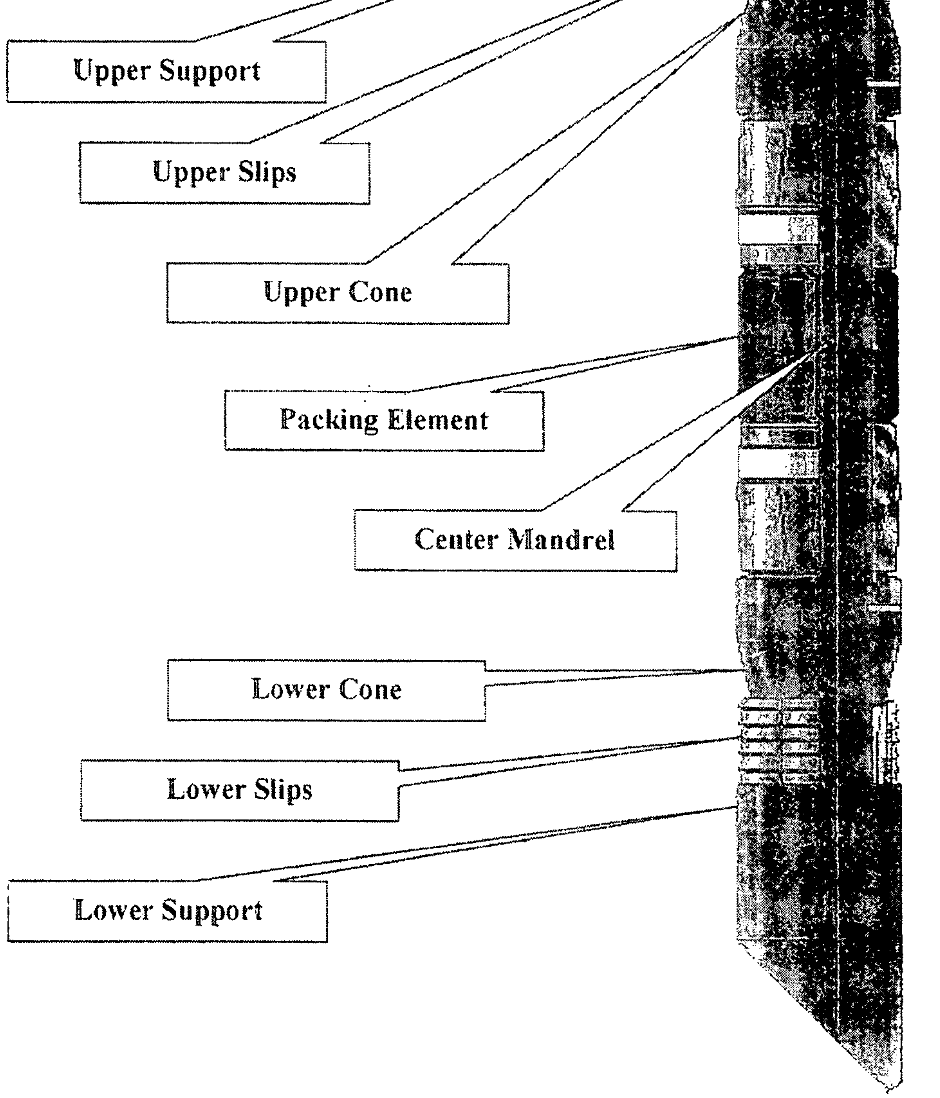
Weatherford
Completion Systems

FracGu[illegible]™ Series Composite Bridge Plug (BP8 and BP10)



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BJ PYTHON™ COMPOSITE BRIDGE PLUG*

TOOLS

Product Information

PRODUCTS AND SERVICES

Description

The BJ Services Composite Bridge Plug (called Python) is constructed of high-tech composite materials, which are easily drillable with a coiled tubing unit.

Features and Benefits

Rapid Drill Out
Two tapered mating surfaces at the top and bottom of each plug rotationally lock plug remnants, promoting ultra-fast drill out.

High Temperature Rating
The tool is designed to operate in 4½", 9.5-15.1# casing at 350°F with 10,000 psi differential pressure.

Slip Design
The slip design combines good bite into the casing with easy drillability.

Standard Deployment
The tool is run on the Baker #10 Wireline Pressure Setting Assembly.

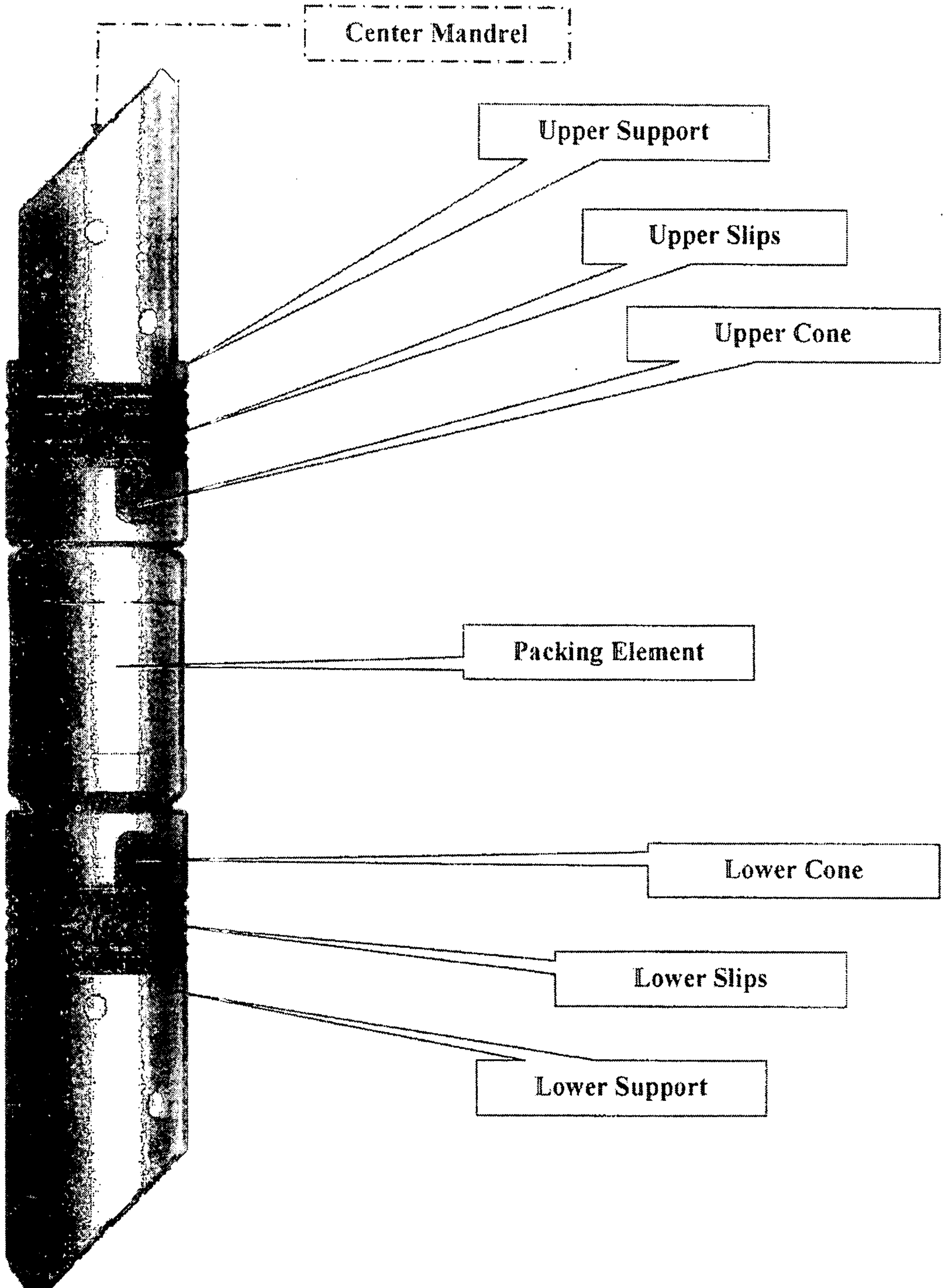
*Patent Pending

BJ PYTHON™ COMPOSITE BRIDGE PLUG

TOOLS

Product Information

PRODUCTS AND SERVICES



BJ000002

B000114

A PRIMER OF OILWELL DRILLING

A Basic Text of Oil and Gas Drilling

Sixth Edition

by Ron Baker

published by

PETROLEUM EXTENSION SERVICE
The University of Texas at Austin
Continuing & Extended Education
Austin, Texas

in cooperation with

INTERNATIONAL ASSOCIATION
OF DRILLING CONTRACTORS
Houston, Texas

2001

Library of Congress Cataloging-in-Publication Data

Baker, Ron, 1940–
A primer of oilwell drilling: a basic text of oil and gas drilling / by Ron Baker. — 6th ed.
p. cm.
ISBN 0-88698-194-8 (alk. paper)
1. Oil well drilling. I. University of Texas at Austin. Petroleum Extension Service. II. Title.
TN871.2B3162001
622'.3382—dc21
00-011902 CIP

First edition published 1951. Fifth edition 1994
Sixth edition 2001
Second Impression 2001
Printed in the United States of America

Catalog No. 2.00060
ISBN 0-88698-194-8

Completing the Well

12

The operating company carefully considers the data it obtains from the tests. Then it decides whether to set production casing or liner and complete the well or to plug and abandon it. If the company decides to abandon it, the hole is *dry*. Dry in the sense of an oil or gas well means the well cannot produce oil or gas in commercial quantities. Some oil or gas may be present but not enough to justify the expense of completing the well. If the well is dry, the operator hires a cementing company to place several cement plugs in the well to seal it permanently.

SETTING PRODUCTION CASING

If the operator decides to set production casing, a supplier brings it to the well. For the final time, the casing and cementing crews run and cement a string of casing in the well. In the case of our model well, the crew could run 5-inch (127-millimetre) casing in the 7⅞-inch (200-millimetre) hole. Keep in mind that the operator may elect to set a liner string. As you recall, a liner string is the same as a casing string except that a liner does not run all the way to the surface. Instead, the casing crew hangs it inside a previously run casing or liner.

Usually, the casing and cementing crews set and cement the production casing or liner through the pay zone. The drilling crew drills the hole so that it goes all the way through the producing horizon and stops a short distance below. Then the casing crew runs the production string almost to the bottom of the hole. (It leaves a little room beneath the guide shoe to allow cement to flow out of the casing.) The production casing or liner and the cement actually seal off the producing zone. At this point, the drilling rig and crews are finished with their job: they have drilled, cased, and cemented the well to the depth specified by the drilling contract. Their only remaining job is to disassemble the rig (rig down) and move it to the next drilling location.

PERFORATING

The operator is not through, however. Because the production string and the cement seal the producing zone, the operator has to provide a way for oil and gas to get from the formation and into the well. Usually, the operator hires the services of a completion rig, which is a relatively small portable rig whose crews perform the final operations required to bring the well into production (fig. 179).

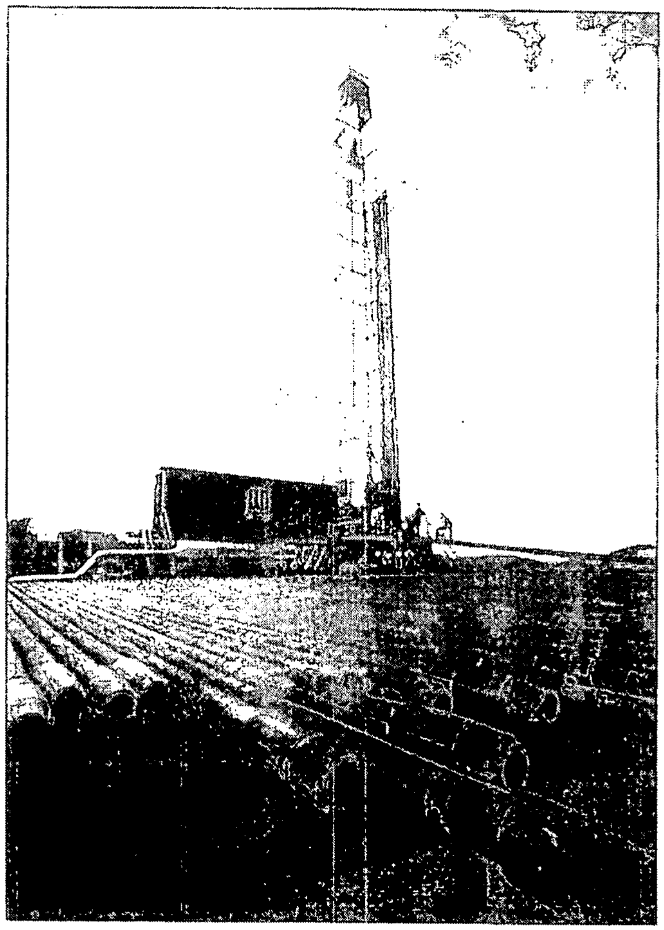


Figure 179. This small rig is a well servicing and workover unit. The operator often employs such units to complete a well.

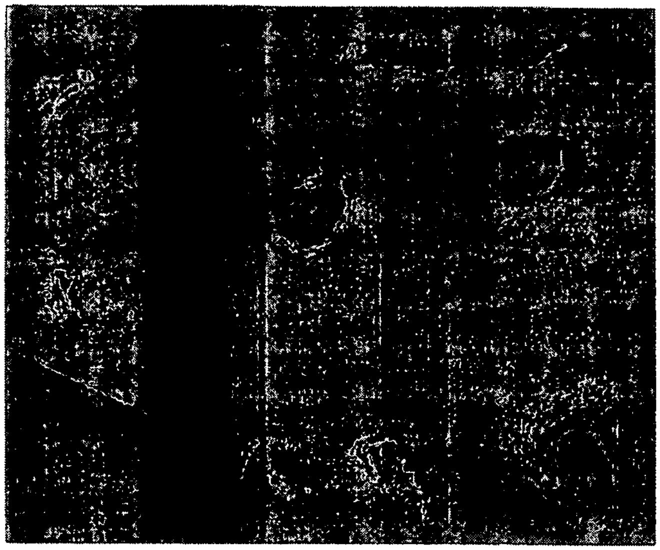


Figure 180. Perforations (holes)

One important task is to perforate the well. A special gun shoots several relatively small holes in the casing. It makes them in the side of the casing opposite the producing zone. These holes, or *perforations* (fig. 180), pierce the casing or liner and the cement around the casing or liner. The perforations go through the casing and the cement and a short distance into the producing formation. Formation fluids, which include oil and gas, flow through these perforations and into the well.

The most common perforating gun uses shaped charges, similar to those used in armor-piercing shells. Several high-speed, high-pressure jets of gas penetrate the steel casing, the cement, and the formation next to the cement. A perforating specialist installs the charges in the special gun and lowers it—usually on wireline, rather than drill pipe—into the well to the desired depth. The depth can be determined by running a collar locator log, which identifies the depth of each casing collar. By comparing the log with the overall number and length of the casing joints, the operator can accurately determine the depth. Once at the desired depth, the perforating specialist fires the gun to set off the charges (fig. 181). After the gun makes the perforations, the perforating specialist retrieves it.

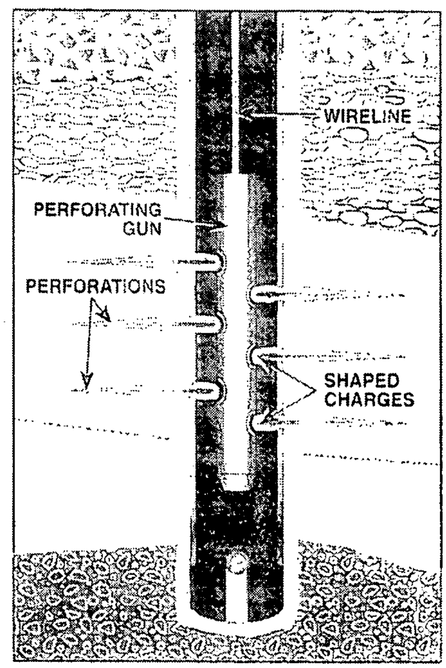


Figure 181. Shaped charges in a perforating gun make perforations.

RUNNING TUBING AND INSTALLING THE CHRISTMAS TREE

After the well is perforated, oil and gas can flow into the casing or liner. Usually, however, the operator does not produce the well by allowing hydrocarbons to flow up the casing or liner. Instead, the completion rig crew places small-diameter pipe called "tubing" inside the cased well. In fact, the operator sometimes runs tubing into the well before perforating it. In such cases, the perforating gun is lowered through the tubing to the required depth.

Tubing that meets API specifications has an outside diameter that ranges from 1.050 inches (26.7 millimetres) to 4½ inches (114.3 millimetres). Seven sizes between the two extremes are also available. As it does with casing, the crew commonly uses couplings to join tubing, although an integral-joint tubing is available that allows the crew to make up joints without using couplings.

Manufacturers also supply *coiled tubing*. Coiled tubing is a continuous length—it does not have joints—of flexible steel pipe that comes rolled on a large reel. Operators have completed wells over 20,000 feet (6,000 metres) deep with coiled tubing. Special equipment placed at the top of the well allows crew members to insert, or inject, the tubing into the well as they unwind it from the reel (fig. 182). The main advantage of coiled tubing is that crew members do not have to connect several single joints of tubing when installing the string. Consequently, coiled tubing takes considerably less time to run.

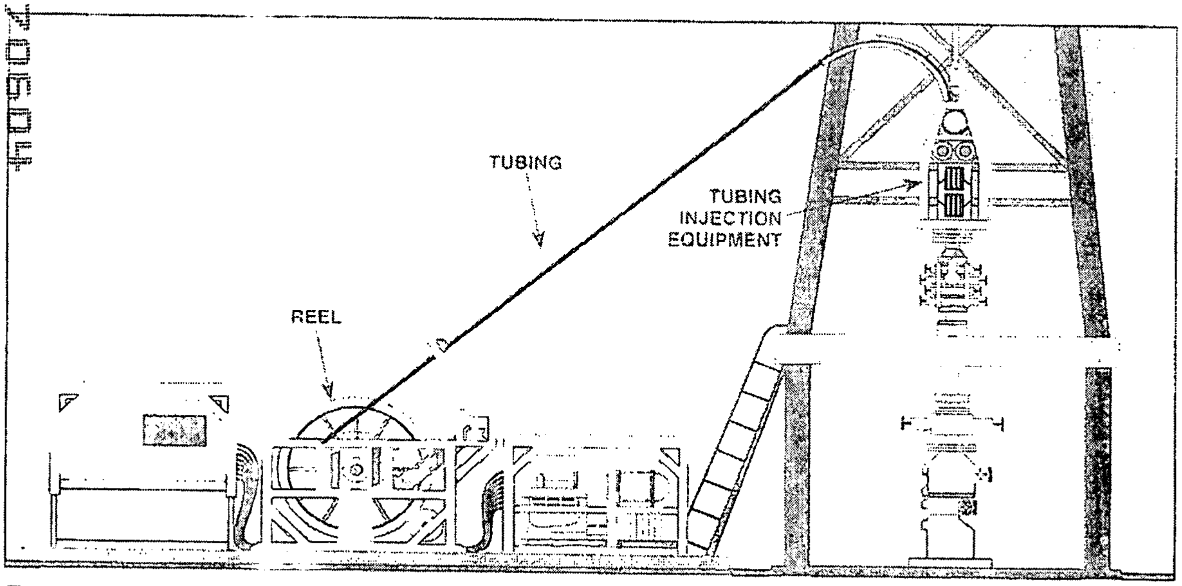


Figure 182. A coiled-tubing unit runs tubing into the well from a large reel.

Whether using jointed or coiled tubing, the operator usually produces a well through a tubing string rather than through the casing for several reasons. For one thing, the crew does not cement a tubing string in the well. Accordingly, when a joint of tubing fails, as it almost inevitably will over the life of a well, the operator can easily replace the failed joint or joints or, in the case of coiled tubing, remove and repair or replace the failed area. Since casing is cemented, it is very difficult to replace.

For another thing, tubing allows the operator to control the well's production by placing special tools and devices in or on the tubing string. These devices allow the operator to produce the well efficiently. In some cases, the operator can produce the well only by using a tubing string. Casing does not provide a place to install any tools or devices that may be required for production. In addition, the operator installs safety valves in the tubing string. These valves automatically stop the flow of fluids from the well if damage occurs at the surface.

Finally, tubing protects the casing from the corrosive and erosive effects of produced fluids. Over the life of a well, reservoir fluids tend to corrode metals with which they are in contact. By producing fluids through the tubing, which the operator can easily replace, the casing, which is not so easy to repair or replace, is preserved.

Crew members usually run tubing into the well with a sealing device called a "packer." They install the packer on the tubing string and place it at a depth slightly above the casing perforations. The end of the tubing is left open or is perforated and extends to a point opposite the perforations in the casing. The packer expands and grips the wall of the production casing or liner. When expanded, the packer seals the annular space between the tubing and the casing above the perforations. The produced fluids flow through the perforations and into the tubing string. The packer prevents them from entering the annular space, where they could eventually corrode the casing.

After the crew runs the tubing string, the operator has a crew install a collection of fittings and valves called a Christmas tree (fig. 183) on top of the well. Tubing hangs from the tree so the well's production flows from the tubing and into the tree. Valves on the Christmas tree allow the operator to control the amount of production or to shut in the well completely to stop it from producing. They also allow the operator to direct the flow of production through various surface lines as required. In addition, a special safety valve on the tree automatically shuts in the well if the tree is damaged. This automatic shut-in valve prevents reservoir fluids from flowing onto the surface if damage occurs. Usually, once the crew installs the Christmas tree, the well is complete.

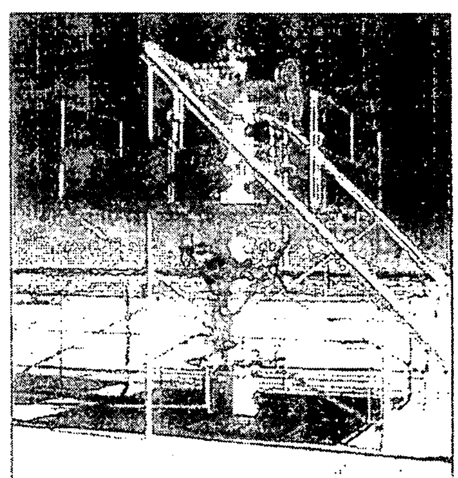


Figure 183. This collection of valves and fittings is a Christmas tree.

ACIDIZING

Hydrocarbons sometimes exist in a formation but cannot flow readily into the well because the formation has very low permeability. If the formation reacts favorably to acid, acidizing may improve flow. An acidizing service company can pump anywhere from 50 to thousands of gallons (or litres) of acid down the well's tubing. The acid, to which the acidizing company adds a chemical to prevent it from corroding the tubing, enters the perforations and contacts the formation. Continued pumping forces the acid into the formation, where it etches channels. These channels provide a way for the formation hydrocarbons to enter the well through the perforations.

FRACTURING

Another treatment that may improve flow is *fracturing*. A fracturing service company pumps a specially blended liquid down the well's tubing and into the perforations. The pumps develop a great deal of pressure at very high rates of flow. Continued pumping causes the formation to split, or fracture, much as a steel wedge causes a log to split. The fracturing crew adds a finely graded sand or similar material (a *proppant*) to the fracturing fluid. The proppant enters the fracture in the formation. When the fracturing crew stops the pumps, the pressure dissipates. With the pressure gone, the fracture tries to close. The proppants, however, hold the fracture open. This propped-open fracture provides a passage for hydrocarbons to flow into the well.

United States Patent [19]

Sukup et al.

[11] **Patent Number: 4,708,202**

[45] **Date of Patent: Nov. 24, 1987**

[54] **DRILLABLE WELL-FLUID FLOW CONTROL TOOL**

[75] Inventors: Richard A. Sukup, Burleson; Monty E. Harris, Azle, both of Tex.

[73] Assignee: The Western Company of North America, Fort Worth, Tex.

[21] Appl. No.: 884,877

[22] Filed: Jul. 8, 1986

Related U.S. Application Data

[63] Continuation of Ser. No. 611,341, May 17, 1984, abandoned.

[51] Int. Cl.⁴ E21B 23/00

[52] U.S. Cl. 166/123; 166/127; 166/133; 166/376

[58] Field of Search 166/118, 123, 127, 128, 166/133, 140, 182, 376

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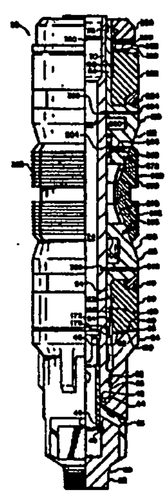
Primary Examiner—Stephen J. Novosad
Assistant Examiner—William P. Neuder
Attorney, Agent, or Firm—Richards, Harris, Medlock & Andrews

[57] **ABSTRACT**

A downhole tool for controlling the flow of fluids through the well casing includes a tubular mandrel with a flow control valve therein. A radially expandable seal member encircles the mandrel and a sub-bottom defines an abutment member, attached to and movable with the mandrel, for engaging one side of the seal member. A bottom cone is positioned around the mandrel and on the opposite of the seal member from the sub-bottom. The cone has a sleeve extending therefrom positioned between the seal and the mandrel on which the seal member is carried. An upper cone is positioned around the mandrel with slips segments being positioned between the upper and bottom cones. An upper radially expandable seal member encircles the mandrel and its carried on a sleeve extending from the upper cone. A lock hub is positioned around the mandrel and on the side of the upper cone opposite the upper seal and slip segments. The hub is slideable on the mandrel toward the sub-bottom for forcing the cones to converge against the slip segments, causing the segments to ride up on the cones and move radially outwardly. Sequentially the expandable seals are compressed and expanded radially outwardly for engagement against the casing wall. To facilitate drillability, components of the tool are formed of a synthetic resin composite, specifically a polyamide material that is glass fiber filled at a level of a minimum of about 30% by weight, having an extremely high modulus of elasticity and having a heat deflection temperature of about 400° F. fully loaded.

32 Claims, 14 Drawing Figures



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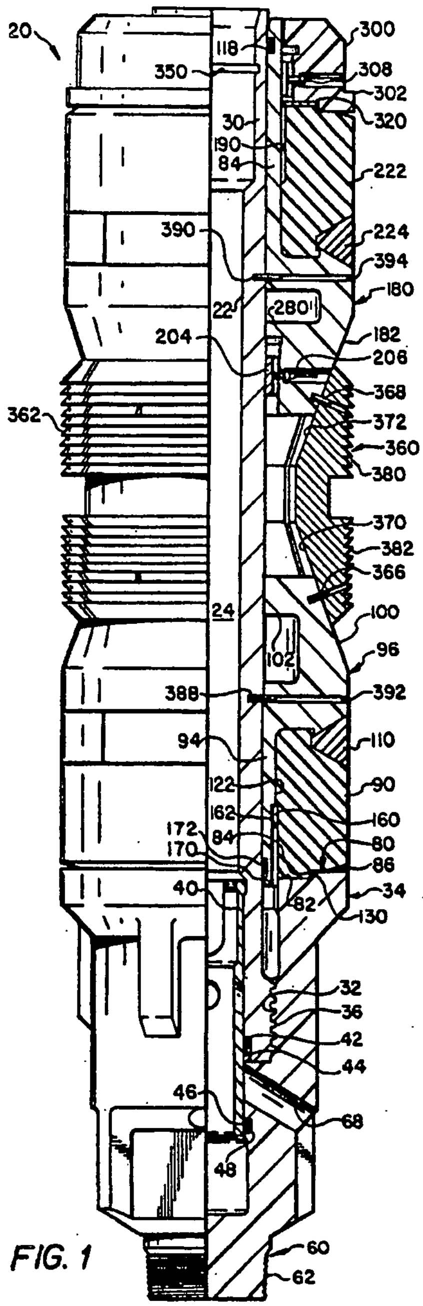


FIG. 1

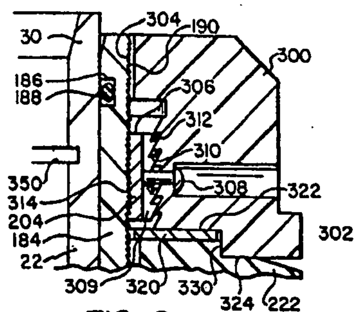


FIG. 2

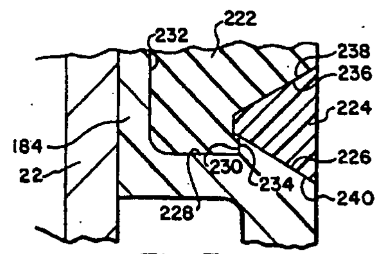


FIG. 3

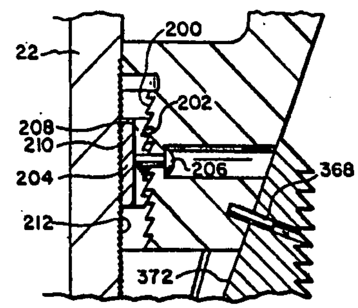
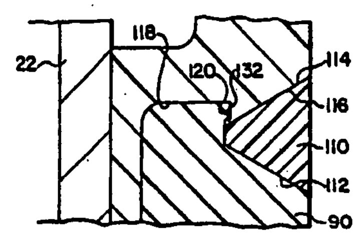


FIG. 4



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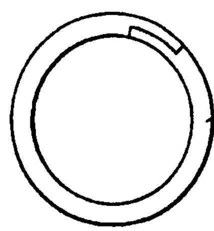

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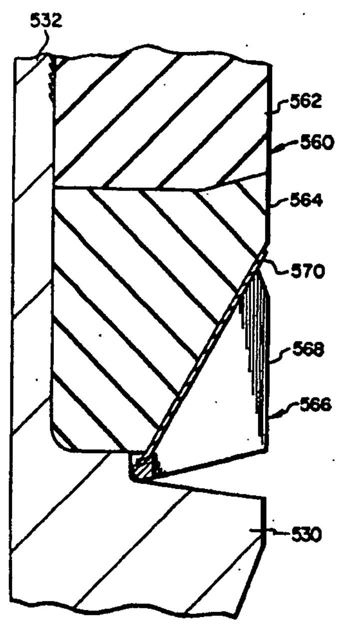

FIG. 11

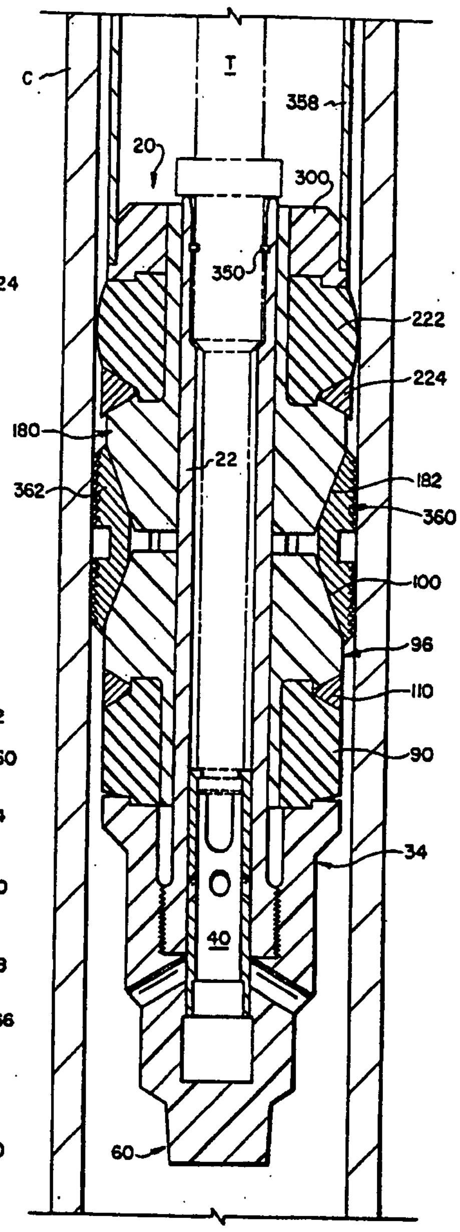

FIG. 7

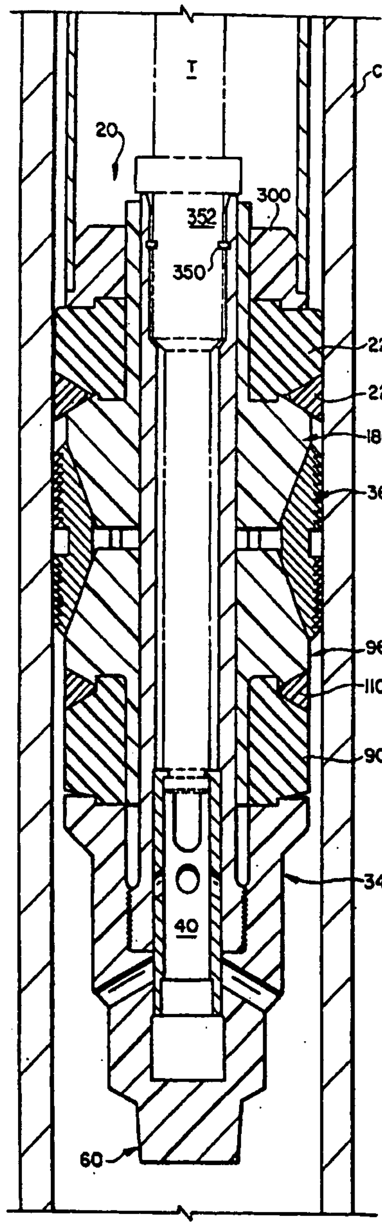
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FIG. 8

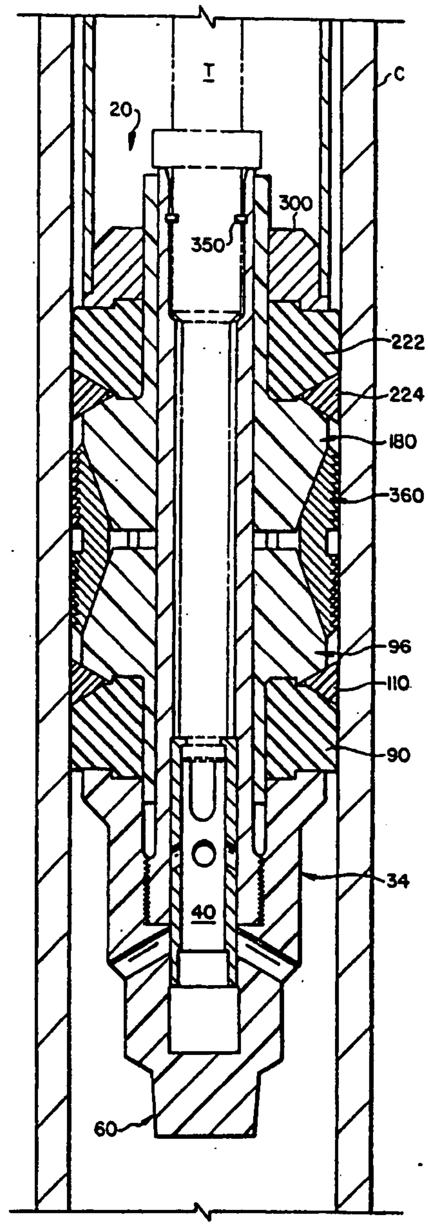
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FIG. 9

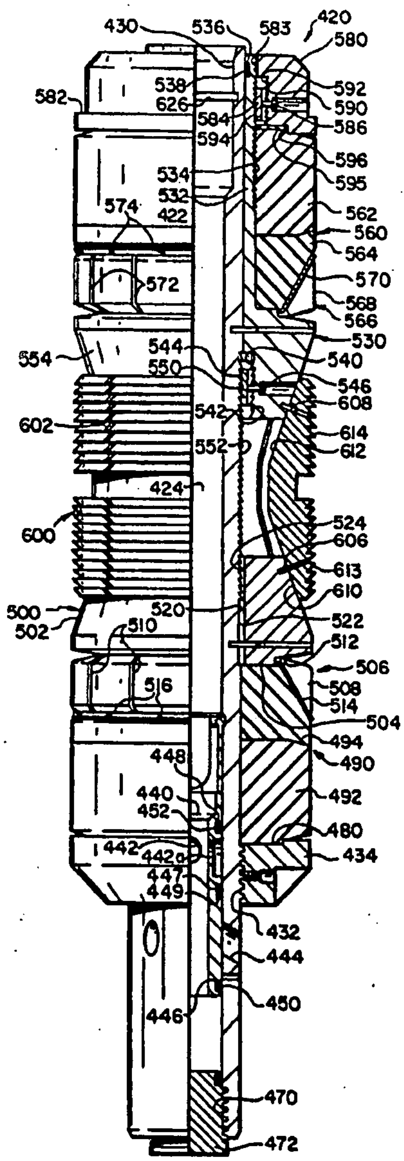
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FIG. 10

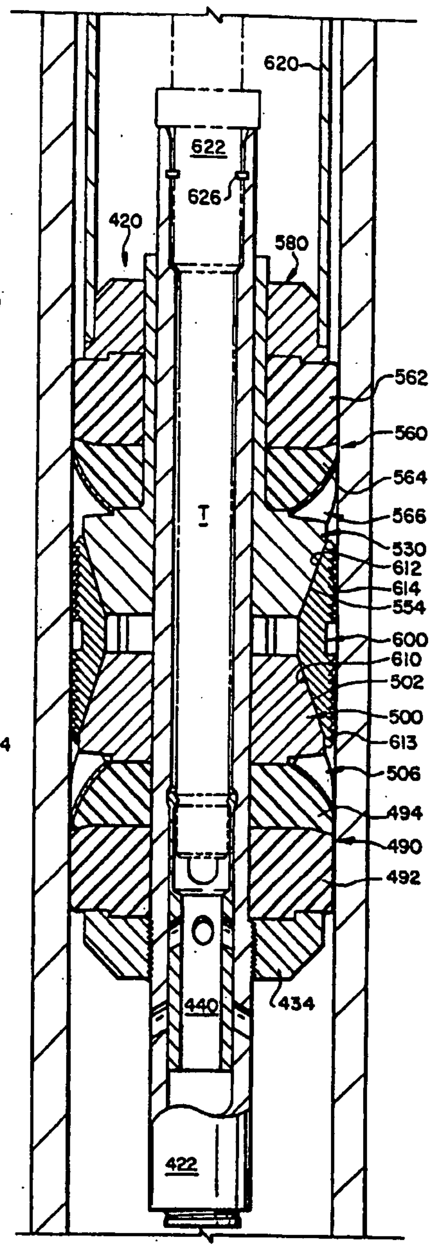
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FIG. 12

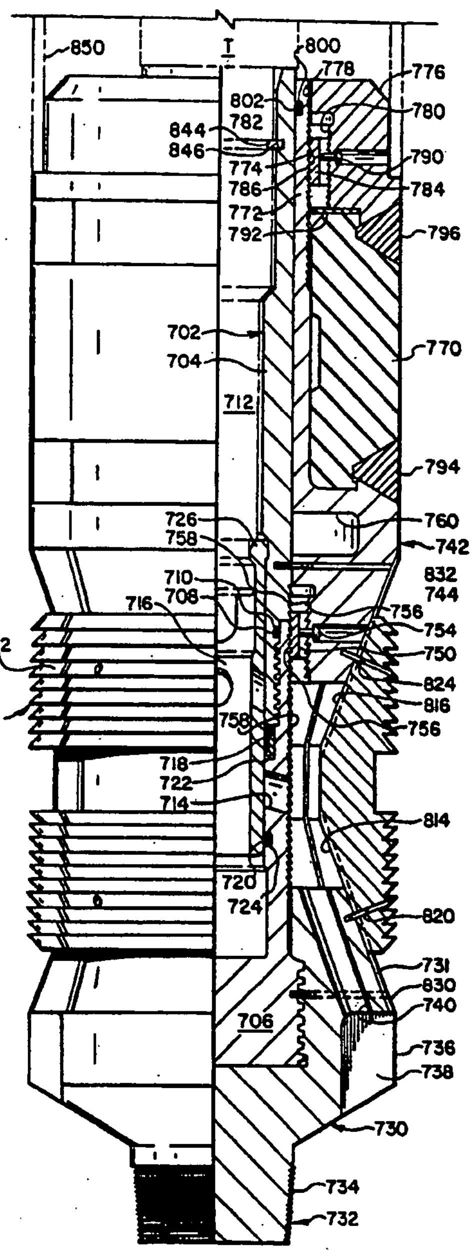
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FIG. 13

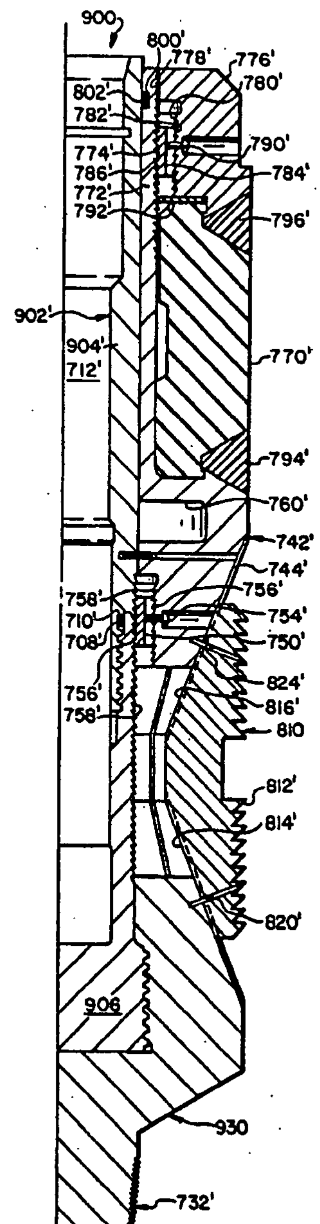
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FIG. 14

DRILLABLE WELL-FLUID FLOW CONTROL TOOL

This application is a continuation of application Ser. No. 611,341, filed May 17, 1984 now abandoned.

TECHNICAL FIELD

The present invention relates to permanent downhole tools used in oil and gas wells and more particularly to tools requiring relatively low setting forces and which are readily drillable for removal.

BACKGROUND ART

Special fluid control tools are used downhole in oil and gas wells during cementing of the well casing as well during well stimulation procedures used to improve well production. These tools include squeeze packers which are used both in completion and increasing production from the well. The cement retainer and bridge plug are examples of squeeze packers commonly used to conduct various downhole completion and service operations.

These production and service tools may be either of the retrievable or permanent type. Retrievable tools are those which may be set and released by manipulating the tool using either the drill string, a wireline or hydraulic control. Because of the additional complexity and expense involved in using retrievable tools, permanent tools are often used in the operation. These tools normally are set in place and are removable only by drilling the tool out of the casing, through conventional rockbit or milling tool methods.

Permanent tools must be substantially built to withstand the pressures and temperatures encountered at the subterranean level at which they are used. Typically, the tools must be made of drillable materials capable of withstanding 30,000 to 40,000 tensile stress and temperatures up to 300° F. In relatively deep wells, that is those deeper than 10,000 feet, even higher pressures and temperatures are encountered.

Squeeze packer production and service tools normally include holding devices, commonly referred to as "slips". These holding devices are used to engage the wall of the casing to restrain tool movement under well bore dynamics Further, the tools incorporate "pack-off" seals for sealing the casing annulus. These seals permit separating areas where differential pressures are applied and for isolating areas within the casing from other areas at varying depth.

Although tools are referred to as "permanent", it may be necessary to remove such tools. This is accomplished by drilling through the tool, and circulating the remains of the tool to the surface for removal. To facilitate drillability of tools, cast iron, rather than steel, is used. Some attempts have been made in the past to use magnesium and other exotic metals which have sufficient strength of material properties. Even using these materials, such tools have required considerable effort to remove through drilling. And because drilling time is rig time, such removal is costly. For example, to remove a permanent cement retainer of the type normally used today, 4 to 6 hours may be required, under ideal conditions.

Further, present design squeeze packers require relatively high internal setting forces and, in many applications, require top and bottom slips with associated cone assemblies for expanding these slips for engagement with the casing wall. As a result of their design, these top and bottom slips are inherently dragged or pulled up the side of the well casing during setting procedures resulting in the "dulling" of the slip teeth. Additionally, present designs often permit the upward movement of the packing element and back up rings during setting, causing a "chafing" of the rubber surfaces. It is not uncommon for a given size squeeze packer or bridge plug to travel four to six inches up the well during setting. Because the tool is not restrained from movement in the casing, the force which can be applied "at the tool" is significantly decreased. Further, the prior art designs which incorporate both top and bottom slips, can result in setting of the tool in a skewed or cocked position in the casing. For example, because the top slip is set first, the tool position upon setting may be skewed relative to the axis of the casing. If this situation occurs, proper setting of the bottom slip may be difficult or impossible. While these designs have been generally acceptable, they have not provided the most efficient arrangement for squeeze packers and related drilling and production tools.

Thus, a need exists for a readily drillable squeeze packer requiring a relatively low internal setting force with an improved holding slip and structure for seating such structure and in expanding the seal pack-off assembly.

DISCLOSURE OF THE INVENTION

The present invention relates to downhole tools for controlling the flow of fluids through the well casing in an oil or gas well. In one embodiment of the invention, the tool is a cement retainer used to pack-off the well casing and permit the injection of cement through a valve in the tool for deposit in the annulus between the casing and the well bore. The tool includes a tubular mandrel having a flow passage therethrough with structure for connecting one end of the mandrel to the well drill string. The second end of the mandrel has a flow control valve therein. A radially expandable seal member encircles the mandrel, and a sub-bottom defines an abutment member, which is attached to and movable with the mandrel, for engaging one side of the seal member. A bottom cone is positioned around the mandrel and on the opposite side of the seal member from the sub-bottom. The cone has a sleeve extending therefrom which is positioned between the seal and the mandrel. Thus, the seal member is carried on the sleeve rather than engaging the mandrel directly. The cone also is designed with a conical surface on a face opposite the seal member.

An upper cone is positioned around the mandrel and has a conical face confronting the conical surface of the bottom cone. Slip segments are positioned around the mandrel and between the cones. The slip segments are designed as a single center slip unit having opposed conical surfaces for cooperating with confronting conical surfaces of the cone members positioned to either side of the slip segments. An upper radially expandable seal member encircles the mandrel and is carried on a sleeve extending from the upper cone. A lock hub is positioned around the mandrel and on the side of the upper cone opposite the upper seal and slip segments. The hub is slidable on the mandrel and may be selectively advanced relative to the mandrel toward the sub-bottom to force the cones to converge against the slip segments. This movement causes the segments to ride up on the conical surfaces of the cones and move

radially outwardly against the casing wall. Sequentially, the expandable seals are compressed and expanded radially outwardly for engagement against the casing wall.

In accordance with a further embodiment of the invention, an annular back-up ring, having a wedge shaped cross section, is positioned between each of the cones and its corresponding seal member. An annular pocket is formed within the cone radially inwardly of the conical surface to remove unnnecessary material to improve drillability. An O-ring seal is positioned in an annular groove formed in the face of the sleeve confronting the mandrel for providing a seal between the sleeve and the mandrel.

In another embodiment of the invention, a single seal member is positioned around the mandrel between an upper cone and lock hub. In this embodiment, a lock hub surrounds the mandrel and is movable toward the abutment member to engage the slip segments on confronting conical members to cause their radially outwardly movememt. Similarly, the seal member is compressed to expand radially outwardly for engagement with the well casing. In this embodiment, the radially expandable seal member rides on a sleeve extending from the upper cone rather than engaging the mandrel.

In another embodiment of the invention, the flow control valve positioned in the mandrel is of the movable sleeve type having a plurality of apertures for registration with apertures in the mandrel sidewall when the valve is in the "open" position. The angle of orientation of the apertures through the sidewall of the mandrel corresponds to that of the apertures through the valve to facilitate flow therethrough. Further, the area defined by the apertures making up the flow channel through the valve is equal to or greater than the cross-sectional area through the setting tool through which fluid flows through the mandrel for discharge through the valve.

In still another embodiment, the tool is used as a bridge plug and therefore does not incorporate a flow control valve.

BRIEF DESCRIPTION OF THE DRAWINGS

For a more complete understanding of the present invention, and for further details and advantages thereof, reference is now made to the following Detailed Description taken in conjunction with the accompanying drawings, in which:

FIG. 1 shows the tool of the present invention in quarter-section and in the unset or running-in position,

FIG. 2 is an enlarged section view of the lock hub and its engagement with the mandrel;

FIG. 3 is an enlargd section of the upper seal, backup ring and upper cone area of the tool,

FIG. 4 is an enlarged section of the upper cone and its engagement with the mandrel,

FIG. 5 is an enlarged section of the lower seal, backup ring and lower cone area of the tool,

FIG. 6 is a plan view of one of the backup rings of the tool,

FIG. 7 is a sectional elevation view of casing within a well bore showing the tool with the slip segments set,

FIG. 8 is a sectional elevation similar to FIG. 7 but showing the tool with the top packing seal set,

FIG. 9 is a sectional elevation similar to FIG. 8 but showing the tool with both the top and bottom packing seals set,

FIG. 10 shows an alternative embodiment of the tool of the present invention in quarter-section and in the unset or running-in position; the tool of FIG. 10 is for use in high pressure, high temperature environments,

FIG. 11 is an enlarged portion of the upper seal and backup ring of the tool shown in FIG. 10,

FIG. 12 is a sectional elevation view of casing within a well bore showing the tool of FIG. 10 in its set position within the casing,

FIG. 13 shows a second embodiment of tool of the present invention in quarter-section and in the unset or running-in position; the tool of FIG. 13 is designed for use in low pressure, low temperature environments, and

FIG. 14 is a quarter-section of an alternative form of the tool of the present invention in the form of a bridge plug.

DETAILED DESCRIPTION

FIG. 1 is a quarter section view of a downhole tool 20 incorporating the present invention. The tool shown in FIG. 1 is a cement retainer, although it will be appreciated that the inventive aspects of the present invention may also incorporated into similar downhole tools used for fluid flow control in the well casing.

Tool 20 includes a tubular mandrel 22 having a central flow passage 24 therethrough. The upper end of mandrel 22 is provided with means, such as box end 30, for joining the tool to a pipe string T (FIG. 7) which extends to the surface of the well. The lower end of the mandrel has threads 32 for receiving a bottom assembly 34. A valve assembly 40 is captured between bottom assembly 34 and the lower end of mandrel 22. An annular sleeve seal 42 is seated between valve assembly 40 and an annular receiving groove 44 in the lower end of mandrel 22 to form a seal between valve assembly 40 and the mandrel. An O-ring seal 46 is seated within gland 48 of bottom assembly 34 to provide a seal between bottom assembly 34 and valve assembly 40. The lower end of bottom assembly 34 has a pin end 60 having threads 62 thereon for receiving other accessories or tools thereon. Bottom assembly 34 has one or more ports 68 therethrough. By selective movement of valve assembly 40, port 68 may be made to register with central flow passage 24 within mandrel 22.

Bottom assembly 34 includes an abutment face 80 transverse to passage 24 with a radially inward portion 82 separated by step 84 from a radially outward portion 86. An elastomeric seal 90 encircles mandrel 22 and is positioned against abutment face 80 as shown in FIG. 1. Elastomeric seal 90, generally referred as a packing element, is separated from mandrel 22 and rides on a sleeve 94 extending from a bottom cone 96 which also encircles mandrel 22. Cone 96 includes a conical outwardly facing surface 100 and has an annular void 102 to eliminate unneeded material to aid in drillability and reduce the engagement surface of the cone with mandrel 22.

Referring to FIGS. 1 and 5, ring backup 110 is positioned between cone 96 and elastomeric seal 90. Ring backup 110 has a wedge cross-section with inwardly tapering side walls 112 and 114 which correspond to complimentary walls on seal 90 and cone 96, respectively. Cone 96 has a conical wall 116 which corresponds to side 114 of ring back up 110. Wall 116 is connected to vertical wall 118 by step 120.

The outside surface of sleeve 94 is defined by a wall 122 which has a key way 162. Seal 90 is formed with steps 130 and 132 for mating with steps 84 and 120, respectively, of bottom assembly 34 and cone 96, respectively, to assist in retaining the seal in position. A

4 0 8 0 7 0 ' 0 7 9 0 0 0 5

square key 160 is seated in key way 162 of sleeve 94 of cone 96 and rides in a key way 164 within bottom assembly 34.

A gland 170 is formed in the inside face of sleeve 94 and receives an O-ring 172. As can be seen in FIG. 1, O-ring 172 forms a seal against mandrel 22.

A top cone 180 encircles mandrel 22 and has a conical downwardly facing surface 182. Top cone 180 also includes a sleeve 184 extending therefrom and having an annular groove 186 near the end for receiving an O-ring 188 for sealing between sleeve 184 and mandrel 22. The outer surface of sleeve 184, over a length adjacent the end thereof, has rachet teeth 190 formed therein for cooperating with a lock ring 204.

Referring to FIG. 4, in conjunction with FIG. 1, the lower end of cone 180 has wickers or teeth 200 for cooperating with teeth 202 of lock ring 204. Rotation of lock ring 204 relative to cone 180 is prevented by use of an appropriate pin 206 which engages slot 208 in lock ring 204. The inside diameter of lock ring 204 is also formed with teeth 210 for cooperating with teeth 212 formed on the outside wall of mandrel 22.

As with lower cone 96, upper cone 180 has material removed to form annular space 280. The top cone is further designed to receive upper seal 222 with a back up ring 224 positioned between seal 222 and top cone 180. Top cone 180 includes a tapered wall 226 separated from a horizontal wall 228 by step 230. (FIG. 3) The outside wall of sleeve 184 is defined by a wall 232. Seal 222 has a step 234 for positioning against step 230 and a tapered wall 236 for cooperating with tapered wall 238 of back up ring 224. Back up ring 224 further has a tapered wall 240 for cooperating with tapered wall 226 of cone 180.

Referring to FIGS. 1 and 2, a lock hub 300 is positioned around mandrel 22 and above seal 222. Hub 300 has collar 302 formed therefrom and a central bore 304 of slightly greater than the outside diameter of sleeve 184. Hub 300 is formed with a concentric bore for receiving lock ring 306 therein which is restrained from rotation by pin 308 which engages slot 309 in ring 306. Lock ring 306 has teeth 310 for cooperating with teeth 312 of hub 300. Lock ring 306 also has teeth 314 on the interior surface for cooperating with teeth 190 of sleeve 184. A ring 320 is received within concentric bore 322 of hub 300. Bore 322 defines a step to a transverse wall 324. Seal 222 is formed with a step 330 for engaging the step formed by bore 322. As can be seen from FIG. 1, seals 90 and 222 may be identical in configuration and not necessarily of the same materials or hardnesses.

Referring to FIG. 1, a slip assembly 360 is positioned intermediate of bottom cone 96 and top cone 180 and has a plurality of slip segments 362 spaced around mandrel 22. Slip segments 362 are also attached to cones 96 and 180 by a plurality of shear pins 366 and 368, respectively, which hold the slips in place. Segments 362 have opposed conical faces 370 and 372 of an angle corresponding to that of conical surfaces 100 and 182 of cones 96 and 180, respectively. Slip segments 362 have teeth 380 and 382 formed therearound. Cones 96 and 180 are attached to mandrel 22 by a plurality of shear pins 388 and 390, respectively. Shear pins 388 and 390 are inserted through apertures 392 and 394 formed in cones 396 and 180, respectively. These pins prevent the premture movement of cones 96 and 180, and thus the premature setting of the slips. In one embodiment of the invention, pins 390 are smaller than pins 388 and require a lower shear force for severing. Thus, in operation of the tool, upper cone 180 may be moved in advance of the movement of lower cone 96.

Operation of the tool is as follows. Referring to FIG. 7, tool 20, mounted on the end of a wire line or drill string using a setting tool T, is run in the well casing C with slip 360, cones 96 and 180 and seals 90 and 222 and lock hub 300 in the position shown in FIG. 1. Setting tool T is attached to tool 20 at shear ring 350 which engages the inside wall of mandrel 22. The setting tool also includes a sleeve 358 which may be moved relative to the structure of the tool engaging shear ring 350 such that it abuts collar 302 of lock hub 300.

With tool 20 positioned within the well casing of the desired depth, the tool is set by advancing sleeve 358 of the setting tool relative to the portion of the tool engaging mandrel 22 by way of shear ring 350. This in turn causes movement of lock hub 300 along mandrel 22 toward bottom assembly 34. As can be seen from the position which is reached in FIG. 7, cones 96 and 180 are moved inwardly relative to slip 360, shearing pins 366 and 368 (FIGS. 1 and 4), and moving the slip segments 362 radially outwardly against casing C. Teeth 210 of lock ring 204 move relative to teeth 212 of mandrel 22, thereby setting top cone 180 relative to mandrel 22. Lock ring 204 prevents the release of this engagement.

The shear pin in the top cone will shear at a predetermined value releasing the cone from the mandrel, and the lower pin shears at a higher value. These shear pins prevent a release of the cones from the mandrel during run-in to avoid a premature set. This sets the tool relative to the casing.

Sequentially, seals 222 and then 90 are compressed longitudinally and as result are expanded radially to engage the wall of casing C to seal off the annulus between the tool and the casing. More specifically, as lock hub 300 moves relative to mandrel 22, the rachet teeth 314 of lock ring 306 move along corresponding teeth 190 of sleeve 184 of cone 180. This results in the longitudinal compression of seal 222 as shown in FIG. 8. In view of the design of these teeth, this compression is not releaseable. At a predesigned setting pressure, sleeve 352 of tool T shears a connection within a portion of the setting tool engaging shear ring 350. In a second sequence step, an upward pull or strain is applied to mandrel 22 to lift bottom assembly 34. Due to the engagement of slip segment 362 against the casing wall, movement of bottom assembly 34 upwardly results in the compression of bottom seal 90 to pack off the seal against the casing as shown in FIG. 9. It can be appreciated that the expansion of backup rings 224 and 110 is corresponding to the expansion of packing element seals 222 and 90. Backup ring 224 acts as a bridge or barrier to limit extrusion of seal 222 from pressure from above. Likewise, backup ring 110 acts as a bridge or barrier to limit extrusion of seal 90 from pressure from below, as shown in FIG. 9. During the upward movement of mandrel 22, teeth 210 of lock ring 204 advance relative to teeth 212 of the mandrel thereby setting the radial expansion of lower seal 90.

As can be appreciated from review of FIGS. 1 and 2, seals 90 and 222 do not ride on mandrel 22 during setting. Instead, sleeves 94 and 184 are positioned between seals 90 and 222, respectively, thereby reducing the relative movement between the seals and their underlying surface. Instead, O-ring seals 172 and 188, positioned between sleeves 94 and 184, respectively, form the seals between the bottom and top cones and mandrel

22. Thus, the load required to set the tool is greatly reduced. Further, the setting of the seals in the present invention are performed sequentially. Thus, the upper seal may be set to withstand a lesser hydraulic pressure than the lower seal, as is often required. Further, the setting of the lower seal, to withstand higher "from below" pressures, can be accomplished with less setting force because of the isolation of the upper seal from direct engagement with the mandrel.

The present design also provides for a single opposed, centered slip design cooperating with confronting cone members for acutating the slips.

With the tool set, cement or other fluids may be directed through the central flow passage 24 and valve 40 for discharge through outlet 68 below the seals 90 and 222.

The tool of the present invention is a "permanent" cement retainer in that once the tool is set in place, release is not possible by mechanical release features. To remove the tool, either for purposes of exploring other zones of interest or to permit the entry of other service or work over tools, the tool is drilled out.

The improved drillability of the present tool is a result of a number of features incorporated in the tool. The present design provides for the forming of a number of the components of the tool from high strength synthetic resins. The most preferred material for these components is a nylon (polyamide) material that is glass fiber filled at a level of a minimum of about 30% by weight, having an extremely high modulus of elasticity and having a heat deflection temperature of about 400° F. fully loaded. Other suitable molded resins may be substituted for the preferred filled nylon, provided they meet the requirements contained herein.

Other suitable materials used to prepare components of the tool should have a modulus of elasticity between about 900,000 to 4,000,000 pounds per square inch, preferrably about 1,000,000 to 3,000,000 pounds per square inch. The material should also have a heat deflection temperature between about 300° F. and 600° F., preferably between about 400° F. to about 525° F., fully loaded. Generally, these will be injected or compression molded thermoplastic or thermoset synthetic resins.

The preferred material exhibits a maximum tensile strength of approximately 30,000 psi and is capable of withstanding temperature of at least 300° F. before experiencing excess growth or elongation. In the present invention, several components may be molded from the above described thermoformed material including bottom assembly 34, ring back up 110, cones 96 and 180, ring backup 224 and lock hub 300. With these components formed from the described materials, drilling time required for removal of the tool of the present invention is greatly reduced. It is expected that in certain applications, drilling times may be reduced by a factor of four.

Thus, the present invention provides a downhole tool and particularly a cement retainer, which requires a relatively low force for setting the tool. The low setting force required is a result of the unique design and positioning of the seals of packer elements relative to the adjacent cone members and positioning of the seal for movement with and separation from the mandrel by a sleeve extending from the bottom and top cone structures. Further, sealing between the cone and the mandrel is by way of a single O-ring for each cone. A single slip assembly is positioned intermediate of the movable bottom and top cone, and expandable pack-off seals are positioned to each side of the cones opposite the slip assembly. Backup rings are incorporated for use in conjunction with the pack-off seals.

Further, the present invention provides a permanent downhole tool that is readily removable by drilling in view of use of synthetic resins as the material of construction for various components in the tool. In one embodiment of the invention, the bottom assembly, bottom and top cones, backup rings and lock hub are made from high strength synthetic resins having relatively high tensile strength, on the order of 30,000 psi maximum, but which is readily drillable compared to cast iron normally used to form these components. With respect to other materials which have been used in the past, such as magnesium or aluminium, the presently described materials provide a tool which is inherently stronger than aluminum or magnesium due to higher mechanical properties and is more easily removed by drilling, requiring less time and less likelihood of damage to drill bits or surface components used in drilling out the tool.

The tool 420 shown in FIG. 10 has some similarity to tool 20 shown in FIGS. 1-9 but is designed for a high-pressure, high-temperature operation. The tool may be used in situations where approximate working pressures of 12,000 psi and temperatures of 350° F. are experienced. The tool in this configuration, when used for high pressure, high temperature conditions, will not incorporate the use synthetic resin components as in the tool disclosed in FIGS. 1-9. However, it will be appreciated that in use of tool 420 for lower pressure conditions and where temperatures will not exceed 300° F., components of the tool may be advantageously made from the synthetic material discussed above.

Tool 420 includes a tubular mandrel 422 having a central flow passageway 424 therethrough. The upper end of mandrel 422 is provided with an opening 430 for receiving a setting tool or a appropriate connector for attachment of the tool to the pipe string or wire line which extends to the surface of the well. The lower end of the mandrel has threads 432 for receiving a bottom assembly 434. A valve assembly 440 is positioned inside the mandrel and has a plurality of ports 442 for registering with ports 444 through mandrel 422 to permit the flow of fluid from the central passageway to the exterior of the tool. The location of this valve assembly 400 inside the mandrel eliminates the need for a housing similar in design to bottom assembly 34 of the embodiment in FIG. 1. Such elimination of a housing made of cast iron for higher order working pressures, reduces overall tool composition and inherently improves drill-out or removal time. Glands 446 and 448 are formed in the valve and receive O-rings 450 and 452, respectively, to provide a seal between the valve and the mandrel. Valve 440 also includes an annular groove 447 for receiving a seal 449 for forming a seal between the valve and the mandrel. A setting tool T is receivable within mandrel 422 for moving the valve between an open and closed position as is well known in the art. Ports 444 have side walls 444a oriented at an acute angle to the longitudinal axis of the tool. Further, ports 442 through valve 440 have side walls 442a oriented at an acute angle to the longitudinal axis of the tool and corresponding to that of walls 444a of ports 444. Thus, when valve 440 is positioned in the "open" position such that ports 442 register with ports 444, the side walls of these ports are aligned to facilitate flow of fluid therethrough. It may also be appreciated that the design of the valve is such that pressure on the bottom side of seal 450 and

449 sees the same pressure as above seal 452, thereby providing equalized pressure over the valve and facilitating its operation.

The lower end of mandrel 422 has internal threads 470 for receiving a plug 472, or other attachment as may be selected by the operator.

Bottom assembly 434 has an abutment face 480. An elastomeric seal 490 encircles mandrel 422 and is positioned against abutment face 480. Seal 490 includes components 492 and 494 having different durometer values as required for the particular application. A bottom cone 500, having a conical face 502 facing away from seal 490, encircles mandrel 422 and has a face 504 for engagement with seal component 494. A two part backup ring assembly 506 is positioned between seal 490 and bottom cone 500. Backup ring assembly 506 includes a carbon steel or ductile iron ring 508 having serrations 510 partially therethrough and connected at the lower end 512. Backup ring assembly 506 also includes a more flexible inner ring 514, also having serrations 516 but connected along the inner diameter. In assembly, serrations 516 are staggered in position relative to serrations 510 of ring 508, as shown in FIG. 10.

Mandrel 422 has a keyway 520 for receiving a key 522 for engaging keyway 524 of cone 500. This engagement prohibits rotation of cone 500 relative to mandrel 422.

A top cone 530 also encircles mandrel 422 and has a sleeve 532 extending therefrom. Sleeve 532 has ratchet teeth 534 formed on the outside surface from the end to a point intermediate of the length of the sleeve. Ring 532 has a gland 536 formed therein and houses an O-ring 538 for sealing engagement between sleeve 532 and mandrel 422.

The lower end of cone 530 has wickers or teeth 540 for cooperating with teeth 542 of lock ring 544. Rotation of lock ring 544 relative to cone 530 is prevented by the use of an appropriate pin 546 which engages a slot in lock ring 544. The inside diameter of lock ring 544 is also formed with teeth 550 for cooperating with teeth 552 formed on the outside wall of mandrel 422.

As with lower cone 500 upper cone 530 has a conical face 554 which confronts the conical face 502 of lower cone 500. As in the earlier embodiments, shear pins are used to maintain lower and upper cones 500 and 530 in position relative to the mandrel prior to setting.

Top cone 530 is designed to receive a top seal 560 over sleeve 532. Seal 560 includes an upper portion 562 and a lower portion 564 having different durometer values as required. A backup ring assembly 566 is also mounted between cone 530 and seal 560 and includes a first ring element 568 and a second ring element 570, both having serrations 572 and 574, respectively, as described with respect to the backup ring assembly 506 positioned adjacent to lower seal 490.

A lock hub 580 is positioned around mandrel 422 and above seal 560. Hub 580 has a collar 582 formed therearound and a central bore 583 of slightly greater diameter than the outside diameter of sleeve 532. Hub 580 is formed with a concentric bore for receiving lock ring 584 which is restrained from rotation relative to the hub by screw 586 which engages a slot in ring 584. Lock ring 584 has teeth 590 for cooperating with teeth 592 of hub 580. Lock ring 584 also has teeth 594 on the inside surface for cooperating with teeth 534 of sleeve 532. A ring 595 is received within a bore 596 of hub 580 and is positioned between seal 560 and hub 580.

A slip assembly 600 is positioned intermediate of bottom cone 500 and top cone 530 and has a plurality of segments 602 spaced around mandrel 422 and connected by wire 604. Slip segment 602 are also attached to the bottom and top cones by a plurality of shear pins 606 and 608, respectively. Segments 602 have opposed conical faces 610 and 612 of an angle corresponding to that of conical surfaces 502 and 554 of cones 500 and 530, respectively. Slip segments 602 have teeth 613 and 614 for engagement with the casing wall as will be described hereinafter.

Operation of the tool is substantially identical to that of tool 20, described hereinbefore. Briefly, tool 420 is run in the well casing with slip 600, cones 500 and 530 and seals 490 and 560 and lock hub 580 in the position shown in FIG. 10. Positioning the tool within the casing is by way of use of a wire line or the drill string with a setting tool T. Tool T has a central sleeve 622 for engagement within mandrel 422 and an outer sleeve 624 which engages collar 582 of lock hub 580. Mandrel 422 is attached to sleeve 622 of the setting tool using a shear ring 626.

With tool 420 positioned in the well casing at the desired depth, the tool is set by advancing sleeve 620. This results in the movement of lock hub 580 along mandrel 422 toward bottom assembly 434. As can be seen from the position which is reached in FIG. 11, the shear pins attaching the cones to the mandrel are sheared and cones 500 and 530 are moved inwardly relative to slip 600, shearing pins 606 and 608, and moving the slip segments 602 radially outwardly against casing C. This sets the tool relative to the casing. Continued movement of lock hub 580 relative to mandrel 422, causes the movement of lock ring 584 relative to sleeve 532 of cone 530. The teeth 594 of lock ring 584 ratchet past teeth 534 of sleeve 532 and seal 560 is compressed causing its radial expansion. Similarly, backup ring segments 566 and 570 fan outwardly as shown in FIG. 12 to provide anti-extrusion and support for the seal components. In view of the design of these teeth, this compression is not releasable.

In a second setting step, and subsequent to the packing off of seal 560, a reverse pull, or strain using sleeve 622 of the setting tool, is applied to mandrel 422 to lift bottom assembly 434 upwardly. In view of the engagement of slip segments 602 against the casing wall, movement of bottom assembly 434 upwardly results in the compression of bottom seal 490 to packoff the seal against the casing as shown in FIG. 12. Simultaneously therewith, backup rings 508 and 514 are fanned outwardly to provide support to the seal element.

The packoff of lower seal 490 is maintained by the engagement of teeth 550 of lock ring 544 with teeth 552 of mandrel 422. As can be seen in FIG. 10, the movement of lock ring 544 relative to cone 530 is prevented by the engagement of teeth 542 against teeth 540 of the cone.

As can be seen from a review of the setting operation, seal 560 is set independently of setting of seal 490. Thus, a different force may be applied to the packing structure to accommodate different forces which will be applied to the tool from below as compared to the hydraulic and other forces from above the tool. Further, seal 560 does not engage mandrel 422 either during the packoff of seal 560 or the packoff of lower seal 490. Thus, a lower setting friction is experienced due to this resulting in lower setting force required.

FIG. 13 illustrates a further alternative embodiment of the present invention showing a cement retainer 700 for use in low-pressure situations. Tool 700 includes a single packing element as compared to the tool of FIGS. 1-9 having both an upper and lower packing seal.

The tool includes a two-piece mandrel 702 having an upper portion 704 joined by appropriate threads to a lower portion 706. A seal 708 is fitted in a gland 710 for providing a seal between portion 704 and 706. Mandrel 702 has a central passageway 712 therethrough which communicates to a plurality of ports 714 through the sidewall of lower portion 706. A movable valve 716 is positioned within the mandrel for movement between an upper and lower position to correspond to a closed and open position with respect to ports 714. Valve 716 is sealed above and below by seals 218 and 222, respectively. Seal 218 is a two piece seal positioned in a bore 722. Seal 720 is an O-ring seal seated in gland 724. As can be seen in FIG. 14, with the valve in the upper position, the upper portion of the valve has a boss which is received within collet groove 726 to maintain the valve in the closed position. The sidewall of valve 716 blocks port 714. With the valve in the lower, or open, position, ports 714 are open to central passageway 712 of the mandrel.

The lower portion 706 of mandrel 702 threadedly receives a bottom shoe assembly 730 thereon having a conical force 731. Bottom shoe assembly includes a pin end 732 with threads 734 for attachment of workover or service tools as required. Shoe assembly 730 includes a plurality of fins 736 and cavity 738 therebetween. Ports 740 are also provided as shown in FIG. 13. An upper cone 742 encircles the mandrel and includes a conical surface 744. The cone 742 has a counterbore 746 with teeth 748 formed internally therein. A lock ring 750 is positioned within the counterbore and has teeth 752 for engagement with teeth 748 of cone 742. Rotation of the lock ring 750 relative to cone 742 is prevented by the use of pin 754 which is received within a slot in the ring. The inner surface of ring 750 is formed with teeth 756 which mate with corresponding teeth 758 on the outer surface of mandrel 702. An annular void 760 is formed within cone 742 to remove material and facilitate the drillability of the tool and also to limit the amount of surface contact between the cone and mandrel to facilitate setting of the tool.

An expandible packer seal 770 is mounted around the mandrel and rides on a sleeve 772 extending from cone 742. Sleeve 772 has teeth 774 formed on the exterior thereof along an appropriate length from the end. A lock hub 776 is received around sleeve 772 and has an aperture 778 which is slightly larger diameter than sleeve 772. Lock hub 776 has a counterbore with teeth 780 formed internally therein for mating with teeth 782 of lock ring 784. Lock ring 784 has internal teeth 786 for engagement with teeth 774 of sleeve 772. Pin 790, positioned through lock hub 776 prevents rotation of lock ring 784 relative to the hub.

Packer seal 770 is positioned between cone 742 and lock hub 776 and has a top spacer ring 792 positioned between the seal and the hub. Two piece backup seal rings 794 and 796 are positioned between cones 742 and the seal and between the seal and lock hub 776, as shown. Backup seal rings 794 and 796 have a wedge cross section. A gland 800 within sleeve 772 of cone 742 receives an O ring 802 for sealing between the sleeve and mandrel 702.

A slip assembly 810 is positioned around the mandrel between shoe assembly 730 and cone 742. Slip 810 includes slip segments 812 having conical surfaces 814 and 816 corresponding to conical surfaces 731 and 744 of shoe assembly 730 and cones 742, respectively. Slip segments are maintained in position, prior to setting of the tool, by use of pins 820 and 824. Conical surfaces 731 and 742 are formed with a plurality of dovetails 830 and 832, respectively for engaging corresponding dovetails on conical surfaces 814 and 816 of slip segments 812 to prevent rotation of the slip segments relative to the tool.

Operation of the tool is as follows. The tool is mounted on a setting tool T having an inner sleeve 842 for receiving a shear ring 844 which is also mounted in an annular groove 846 within the inside wall of mandrel 702. Tool T includes appropriate attachment means for attachment to a wire line or to the drill string, as desired. The setting tool also includes an outer sleeve 850 which engages lock hub 776 at collar 778.

The tool is run into the well casing to a desired depth. By applying a downward pressure through sleeve 850 of setting tool 840, lock hub 776 is moved relative to mandrel 702 and toward shoe assembly 730. Slip segments 812 are caused to ride up on conical surfaces 731 and 744 of shoe assembly 730 and cone 742, respectively, and move radially outwardly for engagement with the casing wall.

The position of slip segments 812 is maintained in the set or radially expanded position by the movement of cone 742 relative to mandrel 702. Lock ring 750 moves downwardly relative to the mandrel with its teeth 756 being ratcheted over teeth 758 of the mandrel and locked in place at the advance position. Movement of cone 742 from the set position is prevented by the engagement of teeth 748 against teeth 752 of lock ring 750. By continuing the application of pressure on lock hub 776, the hub is advanced relative to cone 742 to compress seal 770 and thereby radially expand the seal until contact is made with the casing inside wall. The position of lock hub 776 relative to cone 742 is maintained by the engagement of lock ring 784 with sleeve 772 by way of teeth 786 and teeth 774 on the ring and sleeve, respectively.

With the tool set in place, cement may be delivered through central passage 712, and with valve 716 in the opened position, through port 714 and port 740 of shoe assembly 730. It will be noticed that in the present design, cement will be loaded both in tin cavity 738 and within the area beneath slip segments 812. Thus, the slip segments are maintained in their set position by the presence of such cement and also rotation of the various components relative to the casing is resisted during drillout.

As with respect to the disclosure regarding the tool of FIGS. 1-9, a significant number of the components of tool 700 may be made from a synthetic resin material. Specifically, shoe assembly 730, cone 742, backup rings 794 and 796, and lock hub 776 may be made from the synthetic resin material described hereinabove. Thus, drill out of the present tool is greatly facilitated where removal of the tool is required. As with respect to the tool described in FIGS. 1-9, the present tool may be removed from the casing by drilling in a substantially shorter time than that required for conventional tools.

FIG. 14 shows the application of the present invention to a bridge plug as opposed to the use of the present concept for a cement retainer. A bridge plug differs

from a cement retainer in that it does not incorporate valving structure permitting the flow of fluids beyond the tool location in the casing. The plug is positioned in the casing to provide a bottom to permit flow control operations above the tool, typically flow of fluids into a zone of interest above the bride plug and below a squeeze packer.

Referring to FIG. 14, a bridge plug 900 is shown, incorporating structural components similar to those of tool 700 in FIG. 14. In this tool, mandrel 902 includes an upper portion 904 with a lower portion 906 mated thereto. It will be appreciated that lower portion 906 differs from the lower portion of the mandrel in cement retainer 700 of FIG. 13 by not having any ports therethrough. Further, a control valve is not required as is incorporated in the cement retainer. The bridge plug 900 includes a shoe assembly 930 which is identical to that of shoe assembly 730 of the cement retainer 700 with the exception that ports are not provided through the assembly as exist in the cement retainer. As can be seen in FIG. 14, the remaining components of the bridge plug are identical to those of the cement retainer FIG. 13 and are given the same number, with the addition of the designation prime ('), for purposes of identification. The setting and operation of the bridge plug 900 is also identical to that of the cement retainer 700.

Although preferred embodiments of the invention have been described in the foregoing Detailed Description and illustrated in the accompanying drawings, it will be understood that the invention is not limited to the embodiment disclosed, but is capable of numerous rearrangements, modifications and substitutions of parts and elements without departing from the spirit of the invention. Accordingly, the present invention is intended to encompass such rearrangements, modifications and substitutions of parts and elements that falls within the spirit and scope of the invention.

We claim:

1. A tool for controlling the flow of fluid in a well casing in an oil or gas well comprising:

a tubular mandrel having a flow passage therethrough with means for connecting one end of the mandrel to the well drill string and with the second end having a flow control valve associated therewith,

a radially expandable seal member encircling and carried on said mandrel,

an abutment member attached to and movable with said mandrel for engaging one side of said seal member,

a bottom cone positioned around said mandrel and on the opposite side of said seal member from said abutment member, said cone having a sleeve extending therefrom and positioned between said seal and said mandrel and having a conical surface opposite said seal,

an upper cone positioned around said mandrel and having a conical surface confronting the conical surface of said bottom cone,

slip segments positioned around said mandrel and intermediate of said cones with conical surfaces for engagement with the conical surfaces of said cones, and

a lock hub positioned around said mandrel and on the side of said upper cone opposite said slip segments, said hub to receive applied pressure to move relative to said mandrel toward such slip segments causing radial movement thereof and the compression and radial expansion of said seal.

2. The tool according to claim 1 wherein said abutment member is formed of a high-strength synthetic resin.

3. The tool according to claim 1 wherein said abutment member is formed of a glass-fiber-filled polyamide material.

4. The tool according to claim 1 wherein said bottom and upper cones are formed of a high-strength synthetic resin.

5. The tool according to claim 1 wherein said bottom and upper cones are formed of a glass-fiber-filled polyamide material.

6. The tool according to claim 1 wherein said lock hub means is formed of a high-strength synthetic resin.

7. The tool according to claim 1 wherein said lock hub means is formed of a glass-fiber-filled polyamide material.

8. The tool according to claim 1 further comprising an upper radially expandable seal member encircling and carried on said mandrel intermediate of said lock hub means and said upper cone, and

a sleeve extending from said upper cone encircling said mandrel and positioned between said upper seal and said mandrel.

9. The tool according to claim 8 further comprising: first lock ring means associated with said lock hub for setting said hub relative to the sleeve extending from said upper cone.

10. The tool according to claim 9 further comprising: second lock ring means associated with said upper cone for setting said upper cone relative to said mandrel.

11. The tool according to claim 8 further comprising an annular seal member positioned between the sleeve of said upper cone and said mandrel to form a seal therebetween.

12. A tool for controlling the flow of fluid in a well casing in an oil or gas well comprising:

a tubular mandrel with means for connecting one end of the mandrel to the well string,

a radial expandable seal member encircling and carried on said mandrel,

an abutment member attached to and movable with said mandrel for engaging one side of said seal member,

a cone positioned around said mandrel and one on the opposite side of said seal member from said abutment member,

slip segment positioned around said mandrel with a conical surface for engagement with the conical surface of said cone,

lock hub means positioned around said mandrel on the side of said cone opposite said slip segments, said hub to receive applied pressure to move relative to said mandrel toward said slip segments causing expansion thereof and the compression of said seal, said cone being formed from a high strength synthetic resin material having maximum tensile strength of about 30,000 psi and a modulus of elasticity between about 900,000 to 4,000,000 psi.

13. The tool according to claim 12 wherein said abutment member is formed of a high-strength synthetic resin having a maximum tensile strength of about 30,000 psi and a modulus of elasticity between about 900,000 to 4,000,000 psi.

14. The tool according to claim 12 wherein said lock hub means is formed of a high-strength synthetic resin having a maximum tensile strength of about 30,000 psi and a modulus of elasticity between about 900,000 to 4,000,000 psi.

15. In a downhole tool for controlling the flow of fluid in a well casing in an oil or gas well comprising:

a tubular mandrel with means for connecting one end of the mandrel to the well drill string,

an abutment member attached to and moveable with said mandrel,

lock hub means positioned around said mandrel for movement relative to said mandrel,

a radially expandable seal member encircling and carried on said mandrel intermediate of said abutment member and said lock hub means,

a cone member positioned around said mandrel intermediate of said abutment member and said seal member and having a conical surface,

slip segments positioned around said mandrel and intermediate of said abutment member and said seal member and having a conical surface for engagement with the conical surface of said cone, said hub means adapted to receive applied pressure to move relative to said mandrel toward such slip segment causing expansion thereof and the compression of said seal.

16. The tool according to claim 15 wherein said cone is formed of a high-strength synthetic resin.

17. The tool according to claim 15 wherein said abutment member is formed of a high-strength synthetic resin.

18. The tool according to claim 15 wherein said lock hub means is formed of a high-strength synthetic resin.

19. A tool for controlling the flow of fluid in a well casing in an oil or gas well comprising:

a tubular mandrel with means for connecting one end of the mandrel to the well string,

a radial expandable seal member encircling and carried on said mandrel,

an abutment member attached to and movable with said mandrel for engaging one side of said seal member,

a cone positioned around said mandrel and one on the opposite side of said seal member from said abutment member,

slip segment positioned around said mandrel with a conical surface for engagement with the conical surface of said cone,

lock hub means positioned around said mandrel on the side of said cone opposite said slip segments, said hub to receive applied pressure to move relative to said mandrel toward said slip segments causing expansion thereof and the compression of said seal, said cone being formed from a high strength synthetic material, wherein said cone, abutment member and lock hub are formed of a glass-fiber-filled polyamide material.

20. A tool for controlling the flow of fluid in a well casing in an oil or gas well comprising:

a tubular mandrel with means for connecting one end of the mandrel to the well string,

a radial expandable seal member encircling and carried on said mandrel,

an abutment member attached to and movable with said mandrel for engaging one side of said seal member,

a cone positioned around said mandrel and one on the opposite side of said seal member from said abutment member,

slip segment positioned around said mandrel with a conical surface for engagement with the conical surface of said cone,

lock hub means positioned around said mandrel on the side of said cone opposite said slip segments, said hub to receive applied pressure to move relative to said mandrel toward said slip segments causing expansion thereof and the compression of said seal, said cone being formed from a high strength synthetic material, wherein said lock hub means is formed of a high strength synthetic resin and wherein said synthetic material has a deflection temperature of at least about 400° F. fully loaded and has a suitably high modulus of elasticity.

21. A tool for controlling the flow of fluid in a well casing in an oil or gas well comprising:

a tubular mandrel with means for connecting one end of the mandrel to the well string,

a radial expandable seal member encircling and carried on said mandrel,

an abutment member attached to and movable with said mandrel for engaging one side of said seal member,

a cone positioned around said mandrel and one on the opposite side of said seal member from said abutment member, said cone having a sleeve extending therefrom encircling said mandrel and positioned between said seal and said mandrel,

slip segment positioned around said mandrel with a conical surface for engagement with the conical surface of said cone,

lock hub means positioned around said mandrel on the side of said cone opposite said slip segments, said hub to receive applied pressure to move relative to said mandrel toward said slip segments causing expansion thereof and the compression of said seal, said cone being formed from a high strength synthetic material.

22. In a downhole tool for controlling the flow of fluid in a well casing in an oil or gas well comprising:

a tubular mandrel with means for connecting one end of the mandrel to the well drill string,

an abutment member attached to and moveable with said mandrel,

lock hub means positioned around said mandrel for movement relative to said mandrel,

a radially expandable seal member encircling and carried on said mandrel intermediate of said abutment member and said lock hub means,

a cone member positioned around said mandrel intermediate of said abutment member and said lock hub means and having a conical surface, said cone being formed of a high-strength synthetic resin and said synthetic material having a deflection temperature of at least about 400° F. fully loaded and has a suitably high modulus of elasticity, and

slip segments positioned around said mandrel and intermediate of said abutment member and said lock hub means and having a conical surface for engagement with the conical surface of said cone, said hub means adapted to receive applied pressure to move relative to said mandrel toward such slip segment causing expansion thereof and the compression of said seal.

23. The tool according to claim 22 further comprising an annular seal member positioned between the sleeve of said cone and said mandrel to form a seal therebetween.

24. In a downhole tool for controlling the flow of fluid in a well casing in an oil or gas well comprising:
a tubular mandrel with means for connecting one end of the mandrel to the well drill string,
an abutment member attached to and moveable with said mandrel,
lock hub means positioned around said mandrel for movement relative to said mandrel,
a radially expandable seal member encircling and carried on said mandrel intermediate of said abutment member and said lock hub means,
a cone member positioned around said mandrel intermediate of said abutment member and said lock hub means and having a conical surface, said cone being formed of a glass-fiber-filled polyamide material, and
slip segments positioned around said mandrel and intermediate of said abutment member and said lock hub means and having a conical surface for engagement with the conical surface of said cone, said hub means adapted to receive applied pressure to move relative to said mandrel toward such slip segment causing expansion thereof and the compression of said seal.

25. In a downhole tool for controlling the flow of fluid in a well casing in an oil or gas well comprising:
a tubular mandrel with means for connecting one end of the mandrel to the well drill string,
an abutment member attached to and moveable with said mandrel, said abutment member being formed of a glass-fiber-filled polyamide material,
lock hub means positioned around said mandrel for movement relative to said mandrel,
a radially expandable seal member encircling and carried on said mandrel intermediate of said abutment member and said lock hub means,
a cone member positioned around said mandrel intermediate of said abutment member and said lock hub means and having a conical surface,
slip segments positioned around said mandrel and intermediate of said abutment member and said lock hub means and having a conical surface for engagement with the conical surface of said cone, said hub means adapted to receive applied pressure to move relative to said mandrel toward such slip segment causing expansion thereof and the compression of said seal.

26. The tool according to claim 25 wherein said synthetic material has a deflection temperature of at least about 400° F. fully loaded and has a suitably high modulus of elasticity.

27. In a downhole tool for controlling the flow of fluid in a well casing in an oil or gas well comprising:
a tubular mandrel with means for connecting one end of the mandrel to the well drill string,
an abutment member attached to and moveable with said mandrel,
lock hub means positioned around said mandrel for movement relative to said mandrel, said lock hub means being formed of a high-strength synthetic resin and said synthetic material having a deflection temperature of at least about 400° F. fully loaded and has a suitably high modulus of elasticity,

a radially expandable seal member encircling and carried on said mandrel intermediate of said abutment member and said lock hub means,
a cone member positioned around said mandrel intermediate of said abutment member and said lock hub means and having a conical surface,
slip segments positioned around said mandrel and intermediate of said abutment member and said lock hub means and having a conical surface for engagement with the conical surface of said cone, said hub means adapted to receive applied pressure to move relative to said mandrel toward such slip segment causing expansion thereof and the compression of said seal.

28. In a downhole tool for controlling the flow of fluid in a well casing in an oil or gas well comprising:
a tubular mandrel with means for connecting one end of the mandrel to the well drill string,
an abutment member attached to and moveable with said mandrel,
lock hub means positioned around said mandrel for movement relative to said mandrel,
a radially expandable seal member encircling and carried on said mandrel intermediate of said abutment member and said lock hub means,
a cone member positioned around said mandrel intermediate of said abutment member and said lock hub means and having a conical surface,
slip segments positioned around said mandrel and intermediate of said abutment member and said lock hub means and having opposed conical surfaces, one said conical surface for engagement with the conical surface of said cone, and wherein said abutment member comprises a conical ramp surface for engagement with the other of the conical surfaces of said slip segment, said segments being positioned between said abutment member and said cone member, and said hub means adapted to receive applied pressure to move relative to said mandrel toward such slip segment causing expansion thereof and the compression of said seal.

29. In a downhole tool for controlling the flow of fluid in a well casing in an oil or gas well comprising:
a tubular mandrel with means for connecting one end of the mandrel to the well drill string,
an abutment member attached to and moveable with said mandrel,
lock hub means positioned around said mandrel for movement relative to said mandrel,
a radially expandable seal member encircling and carried on said mandrel intermediate of said abutment member and said lock hub means,
a cone member positioned around said mandrel intermediate of said abutment member and said lock hub means and having a conical surface, said cone having a sleeve extending therefrom encircling said mandrel and positioned between said seal member and said mandrel, and
slip segments positioned around said mandrel and intermediate of said abutment member and said lock hub means and having a conical surface for engagement with the conical surface of said cone, said hub means adapted to receive applied pressure to move relative to said mandrel toward such slip segment causing expansion thereof and the compression of said seal.

30. The tool according to claim 29 wherein said mandrel has a control valve therein for controlling the flow

of fluid through an aperture intermediate said abutment member and once therethrough for communicating fluid from intermediate of said abutment member and said cone member to a point exterior of said slip segments.

31. In a downhole tool for controlling the flow of fluid in a well casing in an oil or gas well comprising:

a tubular mandrel with means for connecting one end of the mandrel to the well drill string,

an abutment member attached to and moveable with said mandrel, said abutment member including a plurality of cavities formed therein with fins extending outwardly adjacent thereto,

lock hub means positioned around said mandrel for movement relative to said mandrel,

a radially expandable seal member encircling and carried on said mandrel intermediate of said abutment member and said lock hub means,

a cone member positioned around said mandrel intermediate of said abutment member and said lock hub means and having a conical surface,

slip segments positioned around said mandrel and intermediate of said abutment member and said lock hub means and having a conical surface for engagement with the conical surface of said cone, said hub means adapted to receive applied pressure to move relative to said mandrel toward such slip segment causing expansion thereof and the compression of said seal.

32. The tool according to claim 31 further comprising an annular seal member positioned between the sleeve of said cone and said mandrel to form a seal therebetween.

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SPE 60312

Improved Completion Method for Mesaverde-Meeteetse Wells in the Wind River Basin

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This paper was prepared for presentation at the 2000 Rocky Mountain Regional/Low Permeability Reservoirs Symposium and Exhibition held in Denver, Colorado, March 12-15.

Abstract

In 1996, Tom Brown, Inc. began drilling new deep Mesaverde-Meeteetse formation wells in the Muddy Ridge field in central Wyoming. The formations consist of many layers of potential pay zones over a long gross interval. Total depth of the wells is about 13,000 ft, with the uppermost pay zones at about 9,500 ft. Over this 3,500-ft gross interval, as many as 50 potential pay zones may be present.

Initial completions consisted of grouping three or four of the best-developed zones together. The zones were then hydraulically fractured and flow-tested for an extended period so production could be determined. Conventional retrievable bridge plugs and packers isolated additional zones as the completion progressed up the hole to new zones. Because of the individual stimulations and extensive flow-testing, the typical well completion lasted several weeks (or months).

The challenge was to find a new streamlined completion method that would reduce the time required to place the wells on production. To meet this challenge, a composite fracturing plug (CFP) was used. A CFP holds pressure from above the tool while successive zones are treated, but it allows flow from zones below it during cleanup.

The current general procedure is to perforate 8 to 10 zones in the lower Mesaverde formation and to perform a hydraulic fracture treatment down the casing. A CFP is then run on wireline and set above the zones just stimulated. Additional Mesaverde zones are perforated, and a second fracturing treatment can be pumped the same day. Finally, tubing with a pumpoff bit is snubbed into the well, and all the CFP's are drilled out. The entire Mesaverde-Meeteetse group of zones was perforated and fractured in 3 to 5 days when this technique was used.

Using composite fracturing plugs has reduced the well completion to a matter of days, and has made rigless completion possible for the stimulation phase.

References at the end of the paper.

Introduction

A two-fold problem was recognized in the completion of the Mesaverde-Meeteetse formation intervals. First, the results of the conventional crosslinked gel fractures performed on initial wells were disappointing, and the fracturing procedures needed to be examined. Second, the completion time was long, and there was some evidence that killing each zone after fracturing may have been detrimental to the well performance. A more effective fracturing technique and a streamlined completion procedure were needed.

In 1996, the first well was fractured with a limited-entry fracturing technique that included a crosslinked gel system. According to openhole log results, four of the best-developed zones were grouped together for a fracturing treatment. It was assumed that the fracture would grow in height into adjacent zones. Four total fracturing treatments were performed in the Tribal MR 30-13 well. Placing the proppant was difficult, and post-fracturing results were disappointing.

In 1998, an examination of the formation mineralogy revealed an acid-soluble material within the natural fractures. Large acid treatments were performed to improve productivity. Initially, the treated zones had high production, but it declined rapidly. Water overflushes and viscous gel spacers were pumped with the acid treatments to increase acid penetration and to maintain higher production rates.

The current process involves perforating all potential zones with 2 shots per foot (spf) (no limited entry), and pumping multistage fracturing treatments. The fracturing treatments consist of repeated stages of acid, slick-water pad, and slick water with low proppant concentrations. Ball sealers are used for diversion. Eight to ten zones are treated simultaneously, and five to seven fracturing treatments are pumped per well. This fracturing technique has resulted in reduced completion times, higher initial production rates, and slower production declines. Fig. 1 (Page 5) shows reduced comple-

tion times, while Fig. 2 (Page 6) shows long-term production results.

Geology and Mineralogy

The Muddy Ridge field is located approximately 25 miles northwest of Riverton, Wyoming in the Wind River Basin. The field was first discovered in 1961 in the shallower Fort Union and Lance formations. By the mid-1990's, four Meeteetse-Mesaverde formation wells had been drilled.

The Upper Cretaceous Meeteetse and Mesaverde formations consist of multiple sand bodies encased in shale sections over a large gross interval. The Meeteetse is found at depths from 9,500 to 11,000 ft. The Mesaverde is located from 11,000 to 13,000 ft. The sands are discontinuous. Detailed sand correlation between wells (80-acre spacing) is not possible.

The Mesaverde formation consists of an upper section dominated by fluvials (including the Teapot member) and a lower series of thinner sand bodies, shales, and coals representative of a lower coastal plain deposition. Immediately above the Cody formation are Mesaverde sands of probable marine or near-marine origin. Sandstones are typically fine or very fine granular salt-and-pepper sands. The "pepper" is a mixture of chert and detrital shale fragments. The primary gas production has been from the middle and lower Mesaverde.

The Meeteetse formation is similar to the Mesaverde in that it consists of discontinuous sand bodies contained within shales. Many zones are thin and poorly developed, with low porosity and no crossover on the neutron density log.

Sidewall core samples were taken from newly drilled wells. When examined, some cores revealed the presence of closely spaced natural fractures. Fracture faces were often coated with ankerite and other iron-rich carbonate minerals.

Completion of the Tribal MR 30-13

In 1996, the Tribal MR 30-13 well was drilled to the Mesaverde formation in the Muddy Ridge field. Because it was the first well drilled there in recent years, extensive flow testing was performed. The overall completion method was to perforate the prospective zones and run in the hole with tubing, a retrievable packer, and a bridge plug. After the perforations were broken down with acid, the tubing and packer were pulled, and the well was fractured down the casing. A wireline bridge plug was set after a set of perforations was tested. New perforations were then added, and the general procedure was repeated. The well was killed with 2% KCl water, and tubing was run in the well to retrieve the bridge plugs.

The first fracturing treatment was performed in the Mesaverde formation in March 1997. For this treatment, four zones were perforated from 12,116 to 12,400 ft. The zones contained a total of 22 perforations at a shot density of 1 spf. The well screened out during the fracturing job. The proppant was cleaned out, and the well was flow-tested for an extended period.

In September, another Mesaverde formation interval was added from 11,594 to 11,935 ft. This interval contained four separate zones and a total of 30 perforations. The zones were fractured with 23,000 gal of borate-crosslinked gel containing 68,000 lb of resin-coated proppant. The well screened out at 5 lbm/gal.

In late September, the Meeteetse formation was perforated from 10,314 to 10,734 ft in four zones with a total of 22 perforations. The Meeteetse formation was successfully fractured with 86,000 gal of borate-crosslinked gel and 310,000 lbm of resin-coated sand at a maximum concentration of 6 lbm/gal.

The retrievable bridge plugs were pulled from the well in November 1997. All perforated and fracture-stimulated intervals were open at this time.

In January 1998, a second group of Meeteetse formation perforations were added from 9,580 to 9,998 ft. These four zones contained a total of 20 perforations. The zones were fractured with 150,000 gal of borate-crosslinked gel and 577,000 lbm of resin-coated proppant at a maximum concentration of 8 lbm/gal. The job was successfully placed at 70 bbl/min.

In April 1998, additional perforations were added in the Meeteetse formation from 9,861 to 10,008 ft. The well was put on sales in mid-May at an initial rate of 3,700 Mcf/D.

Because of the extensive flow testing, this completion lasted from March 1997 to May 1998. The well was considered a data-gathering opportunity for future wells.

Transition Completions

Results of the sidewall core analysis indicated that acid stimulation of the Mesaverde and Meeteetse could be beneficial. Acid-soluble minerals, ankerite and dolomite, were found in the natural fractures of the cores. If these minerals could be dissolved, the permeability of the natural fractures would be enhanced.

Acid fracturing was performed in four wells. First, 100 gal of 15% HCl acid were pumped per foot of perforations. This procedure provided good initial results, but the flow rate declined rapidly. The acid volume was increased to 200 gal/ft of perforations with similar results. Additional stimulations were performed with an acid treatment of 100 gal/ft of perforations followed by a water overflush of 50 gal/ft of perforations. The combination of acid and water overflush provided similar results to the larger acid treatments at a lower cost. Acid treatments were then refined to include viscous gelled spacers that would promote better acid penetration into the formation.

For these transition completions, two basic placement techniques were used. In the first technique, the potential pay zones were perforated based on openhole logs and mud log gas shows. Limited-entry perforating was not used. Perforation shot density was 2 spf. After a group of zones was perforated, retrievable packers and bridge plugs were used to isolate and pump into each set of perforations individually. After the group of zones was acidized, the well was flow-tested. The well was then killed, new perforations added, and the procedure repeated.

For the second method, the treatment was pumped at a high-injection rate (20-bbl/min) down the casing to stimulate several zones simultaneously. Ball sealers were used for fluid diversion. Repeating stages of acid were followed by water overflush. After a group of zones was stimulated, a retrievable bridge plug was set, and new perforations were added and acidized in the same way.

At the end of the well completion, the wells were killed with 2% KCl water, and all the bridge plugs were pulled. Production tubing was run, and the well was put on production.

Current Completion Method

Acid followed by a water overflush initially provided the desired stimulation response, but a long-term solution was needed. In the east Texas Cotton Valley formation, successful stimulations were performed with low-viscosity slick-water treatments that contained low proppant concentrations.[1,2] Therefore, the operator decided to combine the Muddy Ridge acid treatments with the Cotton Valley waterfractures, hoping that even a small amount of proppant might provide long-term production benefits.

The first acid-slick water treatment was used on the Tribal MR 24-41m well. A stage of 15% HCl acid was pumped, followed by a small pad of slick water, and then 20/40-mesh sand was added at concentrations of 0.25 to 1 lbm/gal. Ball sealers were dropped at the end of the 1-lbm/gal stage, and the entire sequence was repeated numerous times. The number of balls dropped and the number of stages pumped depended on the number of open zones and the total number of perforations. Fracturing treatments on later wells included up to 2 lbm/gal of sand. Table 1 (Page 5) shows the pumping sequence currently being used.

The CFP's were first used after the first fracturing treatment was completed on the Tribal MR 25-41m well. A CFP was set above the perforations, and a new set of perforated zones was added. A second fracturing treatment was pumped consisting of a similar sequence of acid and waterfracturing with sand. Then another CFP was set, perforations were added, and the fracturing treatment was performed. The well was flowed overnight to clean up the zones just fractured. Five fracture treatments were pumped in 4 days with four CFP's. The well was then flowed up the casing through all of the CFP's for fracture cleanup. Tubing was snubbed into the well, and the CFP's were drilled out with foam, which prevented well damage. Pressure applied to the tubing pumped off the bit from the end, and the tubing was landed in the perforations for production.

A solution of 15% HCl acid with additives was used in the treatments. The slick-water system was 2% KCl water with a viscosifier to provide 8 to 10 cp apparent viscosity at surface conditions. All the water was treated with biocide, and no surfactants were used in the slick water.

Various proppants have been used in the treatments. Initially 20/40-mesh fracturing sand was used. Later, resin-coated sand and then ceramic proppant were used. The results of using the higher-strength proppant were inconclusive. At this time, the trend is to use resin-coated proppant in the Mesaverde zones and fracturing sand in the Meeteetse zones.

Composite Fracturing Plug

The composite fracturing plug isolated successive fracturing treatments coming up the hole, while allowing production in the zones below the CFP to clean up the treatment.[3]

The CFP (Fig. 3, Page 7) is constructed like a drillable composite bridge plug except that it has a 1-in. diameter hole through its center. A tapered seat, which holds a weighted plastic ball, is located at the top of the tool. When the CFP is placed in the well, the weighted ball sits on the seat and provides a pressure-tight seal to stop any flow through the CFP from above. When zones are being fractured above the CFP, it performs like a bridge plug (Fig. 4, Page 8).

When the well is opened for flow testing, the ball is lifted from its seat in the CFP, allowing the zones below to produce through the center of the tool.

The entire CFP is constructed of easily drillable material. No metal parts are used, only composite material and ceramics in the buttons of the slip wedges that engage the casing. The average drillout time per plug is 15 to 30 minutes.

General Completion Procedure

The following general completion procedure is currently being used. The completion is rigless until the drillout phase.

Day 1

1. Rig up the wireline truck and mast truck or crane.
2. Run a cement bond log.
3. Perforate the first set of Mesaverde zones to be stimulated.
4. Rig up the fracturing equipment.
5. Fracture the first set of Mesaverde zones.
6. Run a CFP on wireline, and set it above the first zones.
7. Perforate the second set of Mesaverde zones.
8. Fracture the second set of Mesaverde zones.
9. Run a CFP on wireline, and set it above the second zones.
10. Perforate the third set of Mesaverde zones.
11. Flow-test the well overnight.

Day 2

1. Fracture the third set of Mesaverde zones.
2. Repeat the appropriate steps until all zones have been stimulated.
3. Flow-test the well up the casing through the CFP to clean up the well.

Day 3

1. Rig up the completion rig and snubbing unit.
2. Snub in the tubing with a bit, and pump off the sub from the bottom of the tubing.
3. Drill out the CFP, using the foam unit as necessary.
4. Pump off the bit.
5. Land the tubing for production.
6. Flow-test the well.

Improvements and Benefits

Three elements are key to the success of the current completions in use.

- All potential pay zones are perforated based on the openhole and mud logs. This practice ensures that each pay sand is stimulated without reliance on hydraulic fracture growth into unperforated zones.
- The combination of acid and slick water with sand provides equal or better zone stimulation than conventional borate-crosslinked gel systems, and the process is more economical.
- The use of the CFP prevents killing the well between fracturing treatments. The CFP is a key element in reducing completion time and improving production results. As many as three fracture treatments have been performed in 1 day when the CFP has been used.

Conclusions

- The use of CFP's has reduced the completion time of the Mesaverde-Meeteetse formation wells in the Muddy Ridge field by allowing multiple fractures per day.
- Perforating all of the zones rather than relying on fracture height growth has helped to ensure that all zones are stimulated.
- The rigless completions made possible by the CFP's have reduced completion time.
- Well-killing operations have been eliminated since retrievable tools are not used.
- Well productivity has been improved by adding CFP's and changing the fracturing techniques to acid/slick water.

Acknowledgments

The authors thank the management of Tom Brown, Inc. and Halliburton Energy Services, Inc. for the opportunity to present this paper. The authors also thank Mr. Ted Enterline, Tom Brown, Inc. geologist, for his insight into the Mesaverde and Meeteetse formations in the Muddy Ridge field.

Nomenclature

bbl/min	=	barrels per minute
CFP	=	composite fracturing plug
cp	=	centipoise
Mcf/D	=	thousand cubic feet per day
spf	=	shots per foot

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3. Guoynes, John, et al.: "Non-Metallic Frac Plug in Coalbed Applications," paper SPE 51053 presented at the 1998 SPE Eastern Regional Meeting, Pittsburgh, PA, November 8-11.

Table 1—Typical Mesaverde - Meeteetse Frac Sequence

Stage	Fluid Type	Event	Fluid Volume	Prop Concentration
1	15% HCl Acid	Acid	3,500	0
2	Slick Water	Pad	1,000	0
3	Slick Water	SLF	4,000	0.25 lb/gal
4	Slick Water	SLF	4,000	0.5 lb/gal
5	Slick Water	SLF	4,000	1 lb/gal
6	Slick Water	SLF	4,000	2 lb/gal
Repeat Stages 1-6 three more times, dropping ball sealers at start of acid.				
7	Slick Water	Flush		

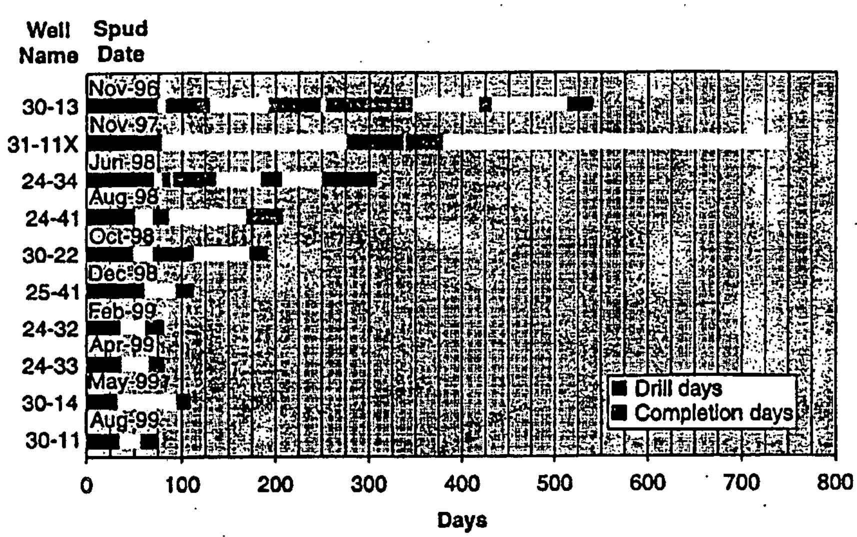

Fig. 1—Muddy Ridge Mesaverde - Meeteetse Program

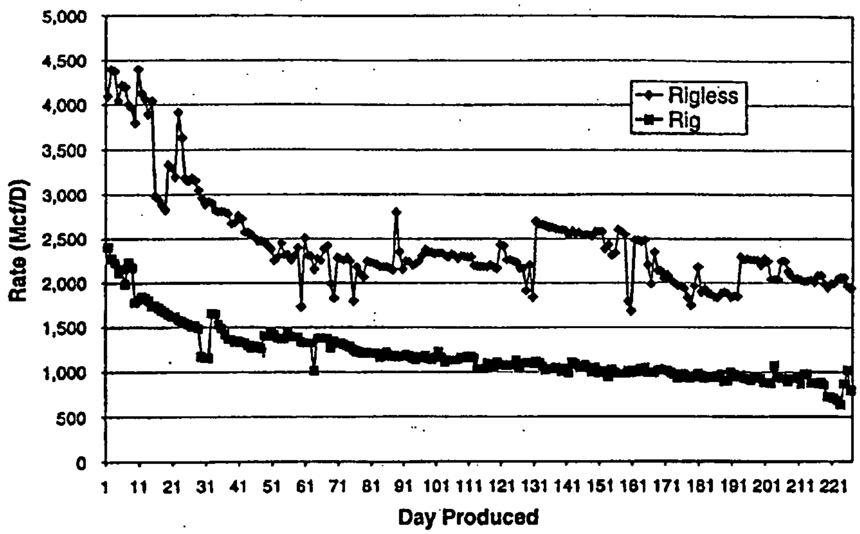

Fig. 2—Comparison of Rigless (CFP) vs Rig (Retrievable Tools) Production

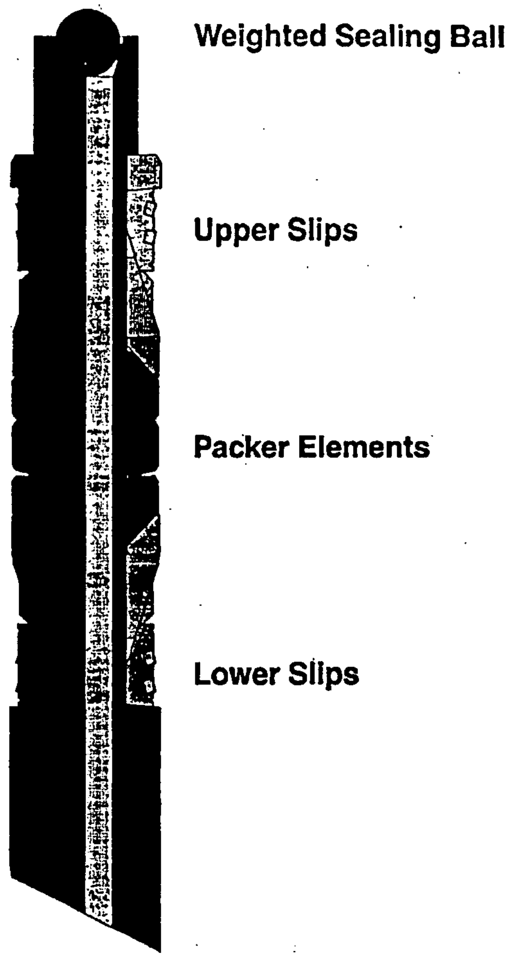

Fig. 3—Composite Frac Plug

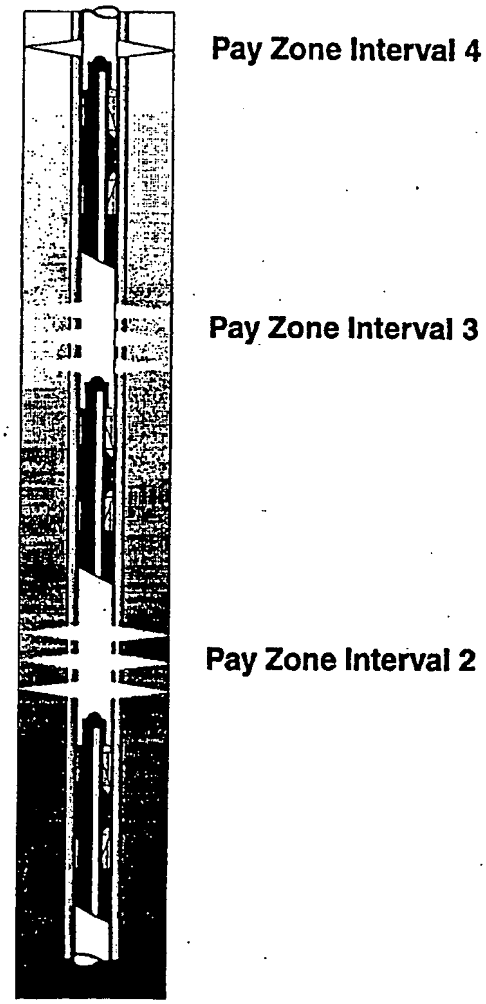

Fig. 4—Stacked Composite Frac Plugs

SPE 71048

The Effect of Stimulation Methodologies on Production in the Jonah Field

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This paper was prepared for presentation at the SPE Rocky Mountain Petroleum Technology Conference held in Keystone, Colorado, 21–23 May 2001.

Abstract

Improvements in stimulation technology have continued to increase our ability to economically extract hydrocarbons from very low permeability reservoirs. The Jonah field, in Southwest Wyoming is a classic example of a reservoir that was commercialized with newer stimulation technology. The Lance formation in the Jonah field consists of several hundred feet of stacked lenticular sands with reservoir permeability to gas less than 10 μD. Completion techniques have evolved over the years employing a variety of hydraulic fracturing techniques. In the past 2 years three techniques have emerged as the predominant completion methods: traditional nitrogen assist, induced stress diversion, and the use of flow thorough composite bridge plugs. This study evaluates the different techniques using spatial sampling to compare each well to its offsets and identify the completion scheme that yields the best results on cumulative production. From this study a clear best practice for completing wells in the Jonah field to maximize production was determined.

Introduction

Jonah field is located in the northwestern corner of the Green River foreland basin (T28 - 29N, R108W) (Fig. 1) between the Wyoming Thrust Belt to the west and the Wind River Mountains to the east. The field is 60 miles north of Rock Springs, Wyoming. By the end of 2000 over 200 commercial wells have been drilled on 40-acre spacing. The eastern (downdip) edge of the field is still being extended. The known limits of the field currently exceed 38 square miles.

Jonah field is bounded on the south and northwest by two wrench faults. Faults within the field boundaries add to the complexity of the reservoirs. Wells within the field encounter overpressured gas at 8,100 to 9,300 ft (0.58 to 0.65 psi/ft gradient) whereas nearby wells drilled across the bounding faults find normal pressure gradients at similar depths.

The Lance formation is Upper Cretaceous in age and consists of 2,000 to 3,000 ft of interbedded fluvial sands, mudstones, and coals. Individual sandstone units range from 5 ft to over 50 ft in thickness and have areal extents ranging from a few acres to 100 acres. Individual sands are geologically heterogeneous reservoirs because of their depositional shapes, but certain stratigraphic intervals consistently have sands developed. Sand-rich intervals are locally called the Upper Lance, Middle Lance, Jonah, Yellow Point, Wardell, and Upper Mesaverde (or Rock Springs). Total net sand in the field ranges from 300 to 600 ft of stacked net pay. Drilling depth ranges from 11,000 to 12,500 ft depending on how many sand packages an operator believes to be economical to develop. More specific geological descriptions can be found in references.[1,2]

Sand porosity ranges from 5 to 14% with relative gas permeability ranging from 0.001 to 0.02 md. Water saturation varies between 30 to 60%; currently there is no significant water production in the field. The producing condensate yield is between 8 to 10 bbl/mmscf with an API gravity of 52°. PVT fluid data are scarce, although the fluid composition appears to be very similar throughout the entire productive section.

Due to the low permeability of the Lance formation in this area stimulation is required for economical production rates. Although all operators use hydraulic fracturing for stimulation there are a variety of different treatment types, fracture isolation methods, and time between treatments.[3,4] Until 1998 the typical treatment consisted of treating three to six individual sands per fracture treatment with the limited entry technique. A total of four to six fracture treatments were performed per well. After a fracture treatment the well was flowed back for 1 week or longer to clean up. Several methods were used to isolate each fracture treatment including pumping a sand plug to cover previous stages to running wireline set tubing retrieve bridge plugs.

An integrated field study completed in 1998 showed a common factor to all the operators was the 60 to 65% completion efficiency.[5] The study presented that the main cause of the low completion efficiency was damage to the hydraulic fractures as a result of methods used for isolating previous treatments in the wellbore. Since 1998 induced

stress diversion became a common completion technique for some operators in the field while other operators now use flow through composite bridge plugs for fracture isolation. In both cases the number of zones treated per fracture treatment has been reduced resulting in more treatments per well. This study evaluates these new completion techniques as well as other current and previous methods.

Completion Types

Traditional completions include the use of sand plugs and wireline-set/tubing-retrieve bridge plugs. Sand plugs, which were the most common method in the early development of, are rarely used now. For a period of time composite bridge plugs were tried but the high-pressure/high-temperature versions were not available. The most common completion method used wireline-set/tubing-retrieve bridge plugs. This technique is used with both the 30 and 70% foam treatments along with some of the nonfoam treatments.

Induced stress diversion (ISD) is a completion technique described by Hewett and Spence[6] as an alternative to limited entry fracturing. ISD depends on two factors 1) stress increases with depth and 2) closure stress increases when the fracture closes on proppant.[7] To further assist in stress diversion, attempts are made to nearly "screen-out" during the treatment by pumping higher proppant concentrations at the end of the treatment. This is done in an attempt to overcome high breakdown and treating pressures up hole. It is also necessary to use some mechanical isolation when a low-pressure zone is treated. Since ISD requires the increased stress from previous fracture treatments it is a continuous process. One advantage to this method is to substantially reduce completion time (2 to 3 days vs. 4 to 5 weeks), which results in significant savings in surface equipment rentals and reduction in fracture equipment charges. It is also important to note that most of these savings can be realized if the well is completed in continuous stages even with the use of mechanical isolation between stages.

Flow through composite bridge plug (FTCBP) is a new item in the composite downhole tools category. Use of FTCBP to isolate hydraulic fracturing treatments has resulted in improved production rates and increased EUR's in several areas.[8]

Composite tool technology has improved greatly in the last 2 years. In addition to being easily drilled up, composite tool can be run at higher differential pressures and temperatures. An FTCBP is a specific tool that does what the name implies; it works as a bridge plug when there is higher pressure above it, such as during a fracture treatment. Then when the pressure above is lower than the pressure below, such as when flowing the well back, the FTCBP allows fluid flow from below through the plug. Allowing all zones to flow during the completion of the well. Two benefits to this are that no zones are shut-in for long periods of time and all previously treated zones help to clean up each new treatment.

After a well is completed the FTCBPs can easily be drilled out or left in the well. Some operators drill out the plugs with a bit and pump-off sub on the end of the tubing. After drillout the tubing is hung off as a velocity string.

Spatial Sampling Analysis

Spatial sampling (also known as moving domain) was presented by Voneiff *e. al.*[9] as a method for evaluating a well to its direct offsets. This technique uses a computer program to step through all wells in the study area individually. As the program steps from well to well, each target, or center, well is compared to all the offsets within a set sample radius called a domain. The primary use of this technique is to identify under performing wells. Depending on the amount of data available, other variables can also be compared between the center well and the offset wells including treatment information, log information, production, etc. Using this information can result in a more detailed understanding of differences in well productivity.

Well Information

For this study production and treatment data were obtained from several public sources. Combing production from each source resulted in a more complete and up-to-date data set than any single data source provided. The area of the study is the Jonah field and includes only those wells located between the wrench faults. This resulted in a total of 177 wells with 1-month production and 162 with 6-month production. One artifact when working with datasets as large as this is there are always individual wells with specific problems; i.e., curtailed production, bride plugs covering some zones, etc. These problems required all data be carefully quality controlled for completeness and accuracy.

Treatment data for these wells were limited, sinceproppant volumes were available for a majority of the treatments but fluid volumes were not available. The main problem with fluid volumes is in the way it is reported when nitrogen is used. Although specific treatment information from public sources is often inaccurate and incomplete the completion type for all wells was determined and placed into five catagories shown below. Although some wells fall into two catagories; i.e., wells completed with FTCBPs and foam, they were placed in only one category.

- Nonfoam - treatments that used mechanical stage isolation and no nitrogen
- 30% - treatments with mechanical stage isolation and 30% nitrogen assist
- 70% - treatments with mechanical stage isolation and 70% nitrogen assist
- ISD - treatments using mostly or all ISD
- FTCBP - treatments using FTCBP for stage isolation

An attempt was made to incorporate log data for evaluating production based on net pay, however, log data were only available on 67 wells. Log data were further complicated because of incomplete perforation information.

The standard for determining the start of production was to base the start of production on the best production month. This offsets the time some operators take to complete wells and partial month production. The map shown in Fig. 2 shows the wells used in this study. The bubble size shown is based on the best month production.

Analysis

The first step for this analysis was to determine the minimum production period that would provide confidence in the study. For this a crossplot of different best-month and 3, 6, and 9-month cumulative gas production (MCGP) was compared to 12-MCGP (Fig. 3). From this crossplot it was determined that 6-MCGP would be used for analysis. It was also determined that because of the good correlation (r^2=0.87) between best-month production and 12-MCGP, best-month production could also be used for evaluating the most recently completed wells.

Production vs. completion date was evaluated to determine if depletion is a factor with the down-spacing wells drilled since 1998. As Fig. 4 shows, there is no indication of depletion with wells completed since 1998. Some of the best wells have recently been completed.

A cumulative frequency chart of 6-MCGP was constructed Fig. 5. This chart shows the median 6-MCGP was 558,000 Mscf and the average was 623,000 Mscf. The chart highlights ISD wells and wells completed with FTCBP. The chart shows that the majority of wells completed with ISD produce less than the average for the field and that five out of seven of the FTCBP wells are in the top third producers. This chart does not show how a well compares to its offsets. Spatial sampling is one way to compare wells and identify differences.

For the spatial sampling analysis presented here the domain area was 640 acres. In the Jonah field a domain of this size typically results in the center well being compared to six to eight offset wells. Other domain sizes, both larger and smaller, were also investigated with similar results. Since detailed log data were not available for the majority of the wells, this analysis was limited to operator, completion type, and proppant volumes using best-month production and 6-MCGP. For all spatial sampling analysis discussed the comparison is based on the value of the center well minus the average value for the offsets. A positive value indicates that the center well has a higher value than the average of the offsets.

Production vs. completion date is evaluated only this time using results from the spatial sampling and comparing completion type (Fig. 6). This chart depicts a large amount of information and is difficult to interpret since there have been continuous changes within each category. Some of what can be gleaned is the early 30% nitrogen treatments performed better than the early non-foam treatments, as will be further demonstrated later. In terms of comparison to offsets the first ISD well was by far the best, and wasalso the best producing ISD well. The success of this well may have been unfortunate in the decision continue with this program since 13 of 21 wells have less production than their offsets. Overall ISD wells average of 18% less production in 6 months than non-FTCBP wells. Conversely, six of seven wells completed with FTCBPs have higher best-month production than their offsets.

Fig. 7 shows a bar chart of the average difference between the center well and offsets for each completion type. The significance of this chart is that it shows that before the introduction of FTCBP there were not any large differences in production between different completion types, +/- 50,000 Mscf in 6 months. However, where FTCBP were used a step change occurred in the productivity of these wells, 0.25 Bcf in 6 months, over their offsets.

Southern Tip Wells. To further investigate the differences in treatment technique, a more detailed study of 60 wells in the southern tip of the field was conducted (these wells are highlighted in Fig. 1.). For this detailed study each well was compared to all the other wells in the area. Since half the wells were completed after July 1999 best-month production is used to maintain the largest sample size (if 6-MCGP is used the number of wells decreases to 46).

A cumulative frequency chart of best month is shown in Fig. 8. This chart shows the median best-month production was 171,622 Mcsf and the average was 174,196 Mscf. These values compare to 130,436 Mcsf and 144,806 Mscf for the field. The chart highlights the ISD wells and wells completed with FTCBP. A better split is seen in wells completed with ISD above and below the average for the area, however seven out of eight of the FTCBP wells are among the top producers.

A chart comparing the center well best month production minus the average of the offset wells vs. completion date (Fig. 9) was constructed. This chart shows a similar result to the cumulative frequency chart - ISD wells on average did worse than their offsets while FTCBP wells did better. It is also interesting to note the decrease with time of the 70% nitrogen treatments. During this time the amount and concentration of 100 mesh being pumped in these wells increased continuously.

A bar chart of completion type for this area (Fig. 10) shows similar results to the field-wide analysis. It is important to note the relatively small sample sizes of some groups, but again there is a significant difference in FTCBP completed wells and the others. A similar bar chart was created to compare proppant treatment volumes (Fig. 11). The chart shows ISD wells used less proppant volumes than the other completion types. Along with proppant volume the number of treatments was compared. Both ISD and FTCBP had averages of eight and nine treatments per well and the foam wells had an average of five treatments per well.

Summary

A variety of different completion techniques have been used in the Jonah field over the last 6 years. In the last 3 years the completions have focused into three basic categories; ISD, foam, and FTCBP. Before the introduction of FTCBPs, ISD wells produced an average of 18% less gas in the first 6 months than other treatments. Depending on the price of natural gas, and whether an operator desires to flow the well between stages, a case may be made for the use of ISD. However, if the operator does not desire to flow the well

between stages then the savings[10] associated with ISD are significantly less and the reduction in productivity should be strongly considered. Remember that 14 of 22 wells completed using ISD have less production than the average of their offsets.

With the introduction of the FTCBP in Jonah there has been a step change in the productivity of wells, 0.25 Bcf in the first 6 months. Five of seven wells completed using FTCBPs out produce the average of their offsets and one produced nearly 1 Bcf more in 6 months (12 of 14 when best month production is used). Combined with more stages and more proppant the benefit to using FTCBPs has not been fully realized yet.

Based on earlier referenced findings that 60 to 65% completion efficiencies were the result of fracture-isolation methods. It is believed that the use of FTCBPs reduces or eliminates post treatment damage to fractures. At the time of this paper production logs were not available to substantiate this statement. However, as shown in **Fig. 12**, incremental production is associated with fracture treatment. This was not the case with other isolation methods when production logs showed over 10% of the fracture treatments did not contribute to production after a well was completed.

Conclusions

1. The use of FTCBPs has resulted in a step change increase in productivity. Because fracture treatments are not damaged by isolation methods, zones are not shut-in for long periods of time, and all previously treated zones help clean up each subsequent treatment.
2. More stages and larger proppant volumes should be evaluated in conjunction with FTCBPs for increasing production.
3. ISD completions result in lower productivity, 18% below pre-FTCBP completions. Any potential savings from ISD need to offset this reduced productivity.

Acknowledgements

The authors thank everyone who helped compile data and provided insight on the analysis. Thanks are also extended to Halliburton Energy Services, Inc. for permission to publish this paper.

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SI Metric Conversion Factors

acres	× 4.047	E-03	= km^2
bbl	× 1.59	E-01	= m^3
ft	× 3.048	E-01	= m
gal	× 3.785	E-03	= m^3
lbs	× 4.536	E-01	= kg
Mscf	× 28.32	E+00	= m^3/day
md	× 9.87	E-04	= mm^2

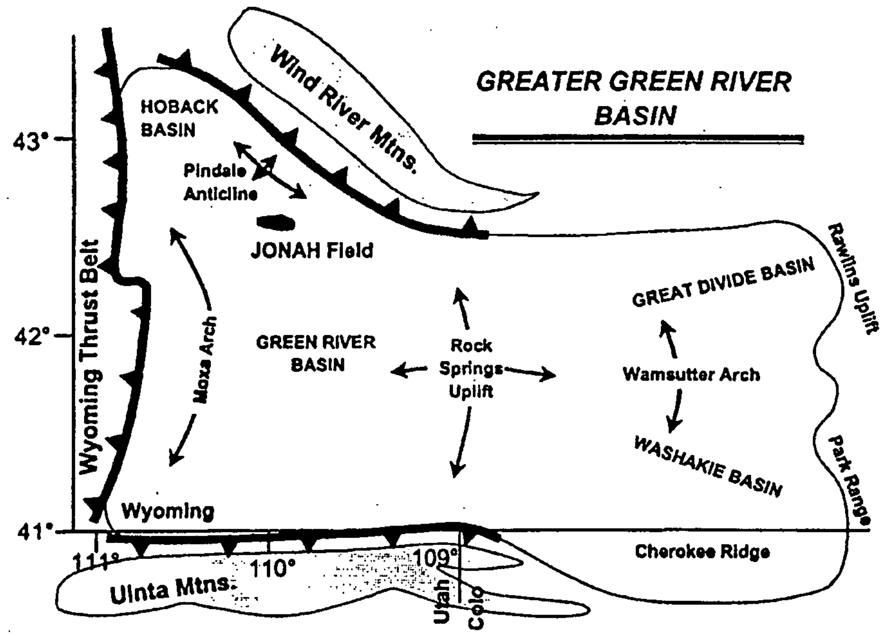

Fig. 1 - Location of Jonah field.

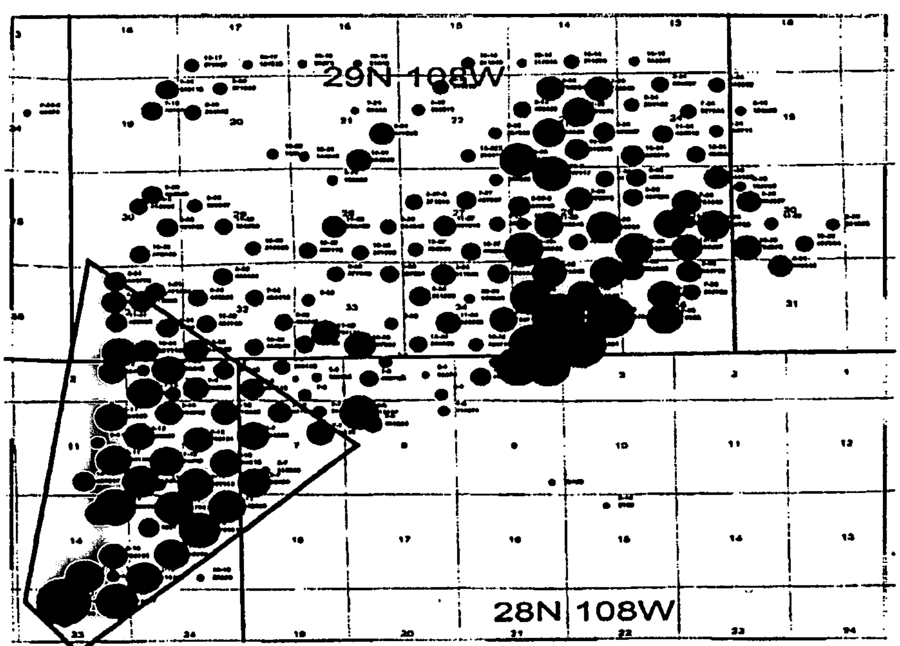

Fig. 2 - Wells included in study area. Bubble size represents 6 MCGP.

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0000704.07060 4

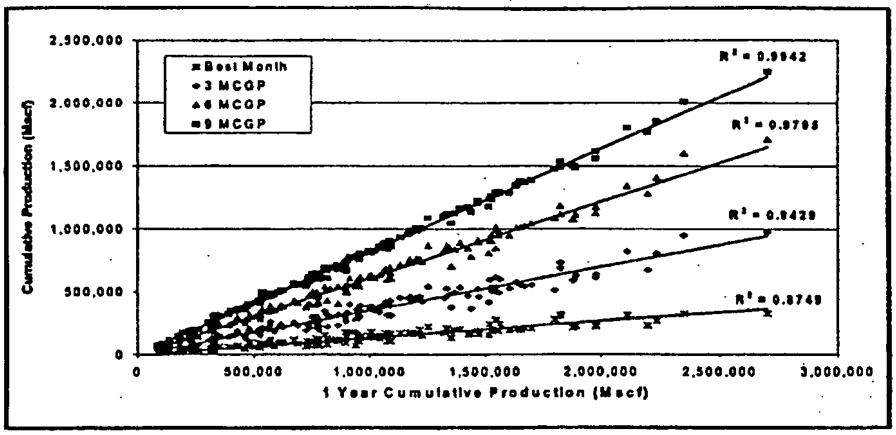


Fig. 3 - Crossplot of 3, 6, and 9 month cumulative gas production versus 1 year for Jonah field.

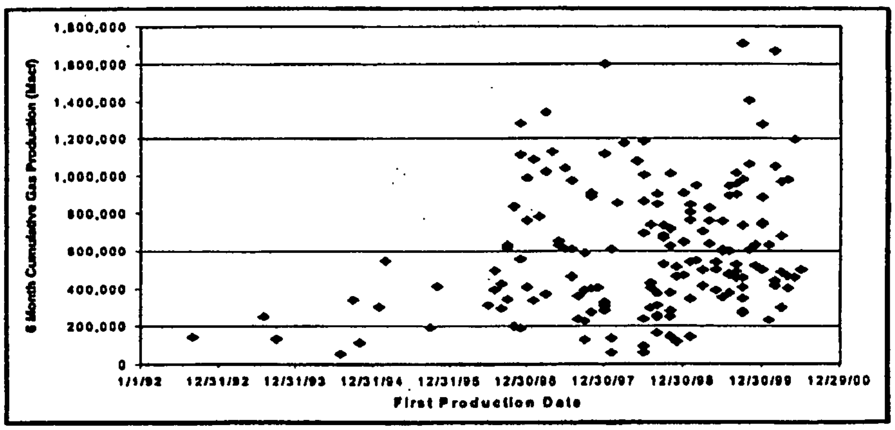


Fig. 4 - Chronology of 6 MCGP based on first production date for Jonah field.

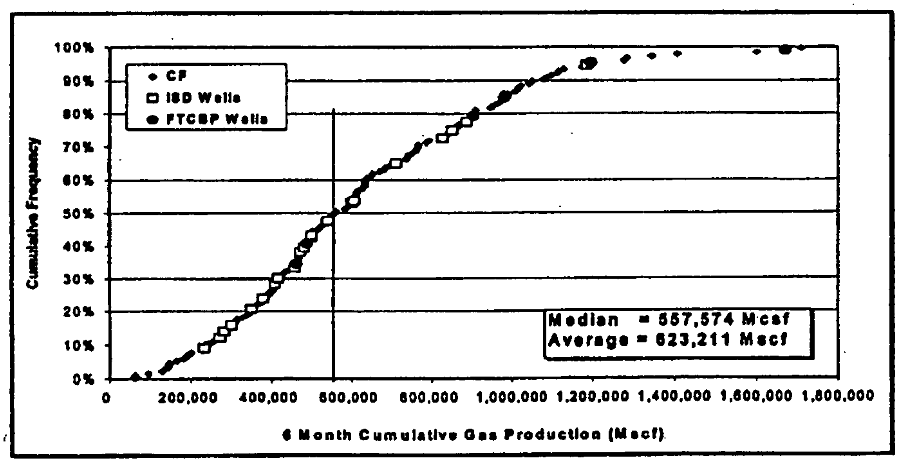


Fig. 5 - Cumulative frequency chart of 6 MCGP for Jonah field.

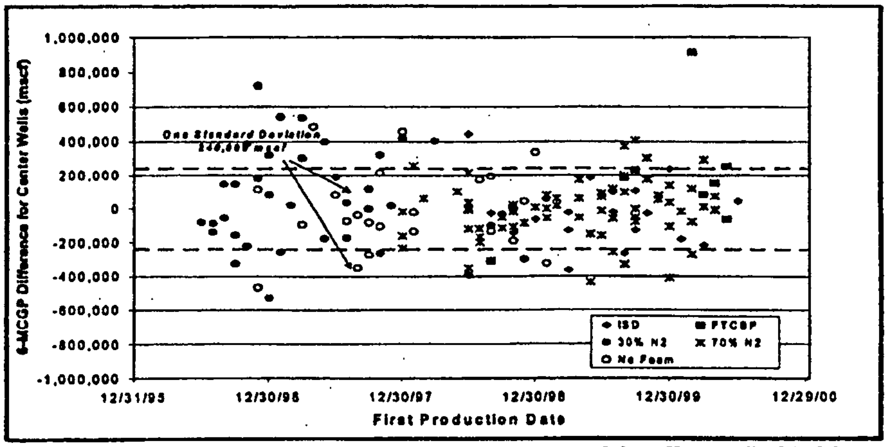


Fig. 6 - Comparison of center well 6 MCGP to the average of the offset wells 6 MCGP by completion date and type for Jonah field.

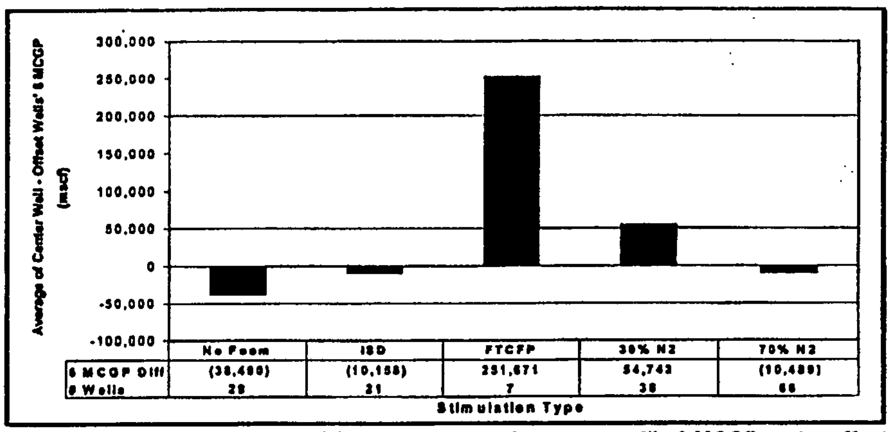


Fig. 7 - Overall average of the difference between the center well's 6 MCGP to the offset well's 6 MCGP based on completion type, Jonah field.

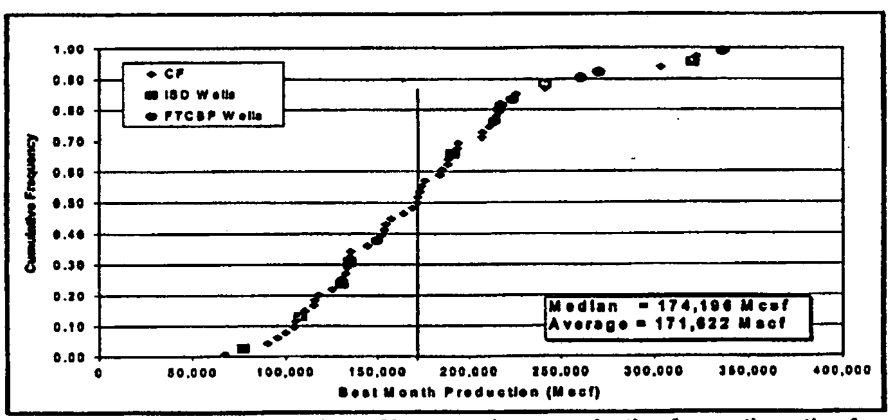


Fig. 8 - Cumulative frequency chart of best month gas production for southern tip of Jonah field.

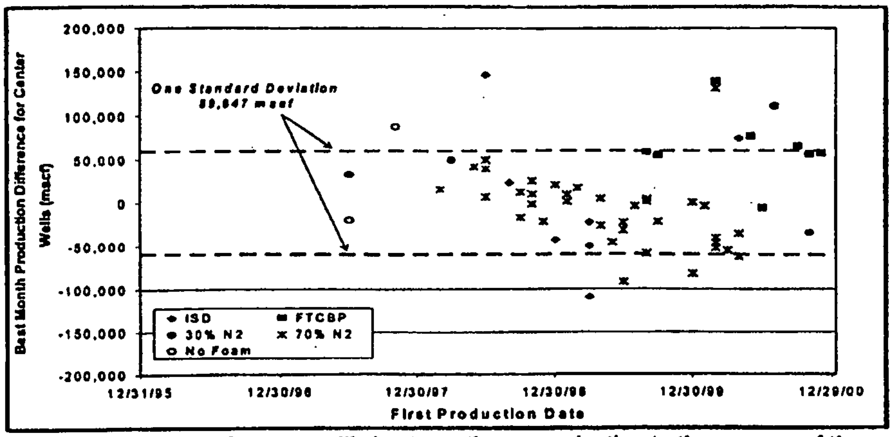


Fig. 9 - Comparison of center well's best month gas production to the average of the offset wells best month gas production by completion date and type for southern tip.

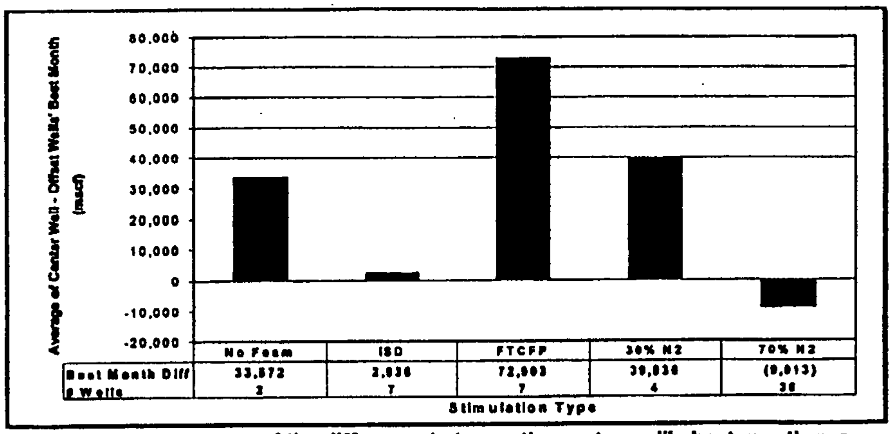


Fig. 10 - Overall average of the difference between the center well's best month gas production to the offset well's 6 best month gas production based on completion type for southern tip of Jonah field.

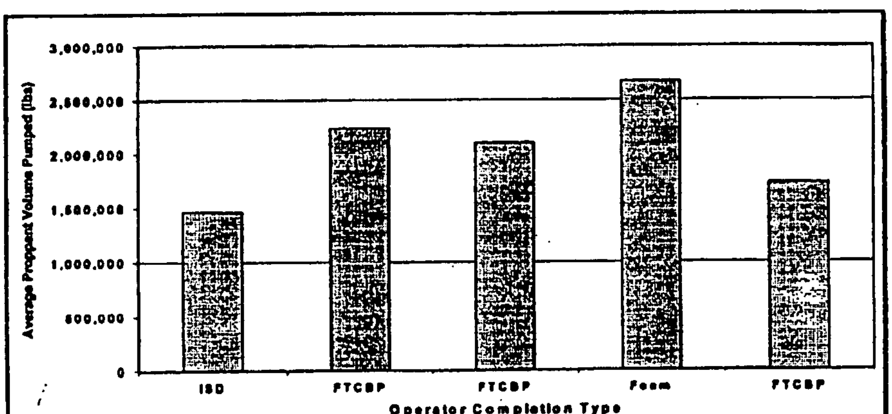


Fig. 11 - Average proppant volume pumped based on treatment type for southern tip.

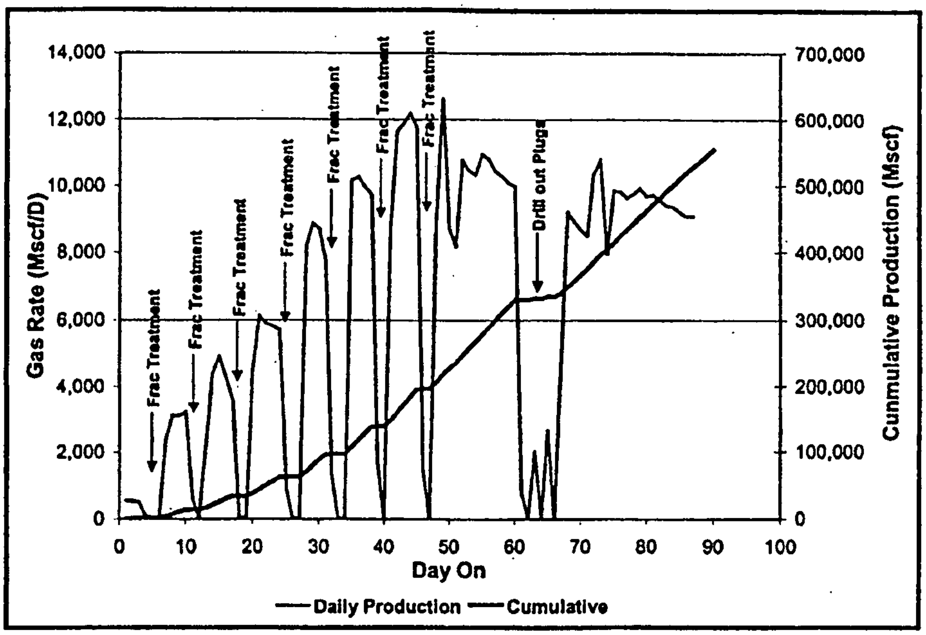
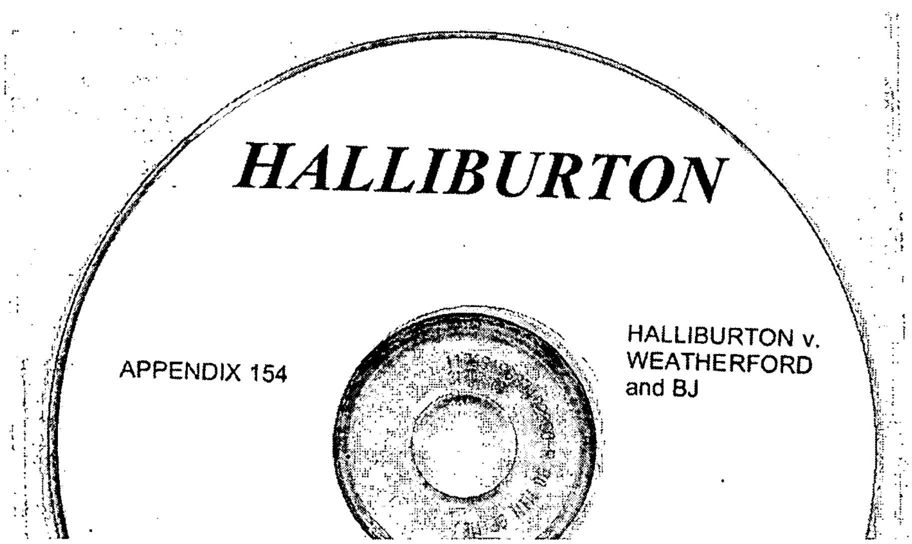


Fig. 12 - Production chart during completion of Jonah well using FTCBP.

Instruction Sheet for
Halliburton Tool Simulator LITE, Service Tools CD-ROM

To access an audio-visual file regarding the FAS Drill Bridge Plug:

1. start the CD-ROM
2. Click on "Main Menu"
3. Click on "Service Tool Systems"
4. Click on "FAS Drill Bridge Plug"
5. Click on "Operating Scenarios and Procedures"
6. Click on "Using FAS Drill for Zonal Isolation"



INFRINGEMENT CLAIM CHARTS
US Patent # 5,271,468
Claim 1

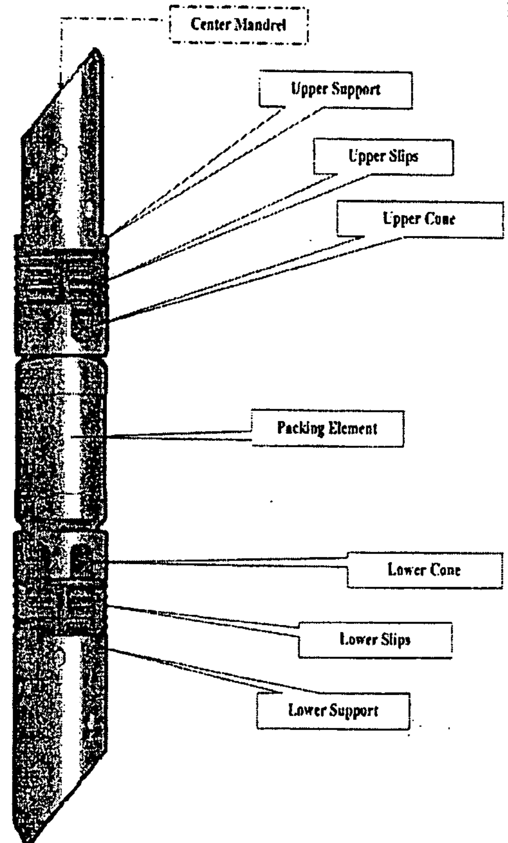
1. A well bore process comprising the steps of:
constructing a downhole tool such that a component thereof is made of a non-metallic material, said tool comprising:
a center mandrel; and
a plurality of slips disposed around said mandrel for grippingly engaging a well bore when in a set position; wherein, at least one of said mandrel and said plurality of slips is said component;
positioning said downhole tool into *locking, sealing engagement* with said well bore; and
drilling said tool out of said well bore. **A 16.**

'468 Patent, Claim 1	**Weatherford's "FracGuard" composite bridge plug and frac plug**	**BJ's "Python" composite bridge plug**
A well bore process comprising the steps of:	Yes. McGowen, ¶ 5, **A99**	Yes. McGowen, ¶ 5, **A99**
constructing a downhole tool such that a component thereof is made of a non-metallic material;	Yes. McGowen, ¶¶ 3, 11(a) , **A98-99, 100-101.**	Yes. McGowen, ¶¶ 4, 15(a), **A99, 103**
said tool comprising a center mandrel and a plurality of slips disposed around said mandrel for grippingly engaging a well bore when in a set position;	Yes. McGowen, ¶ 11(d), **A100-101.**	Yes. McGowen, ¶ 15(d), **A103**
wherein, at least one of said mandrel and said plurality of slips is made of a non-metallic material;	Yes, at least the mandrel is made of a non-metallic material. McGowen, ¶¶ 6, 11(b) , **A99, 100-101.**	Yes, at least the mandrel is made of a non-metallic material. McGowen, ¶¶ 6, 15(b), **A99, 103.**
positioning said downhole tool into locking, sealing engagement with said well bore*; and	Yes. McGowen, ¶¶ 5, 11(c-d) , **A99, 100-101.**	Yes. McGowen, ¶¶ 5, 15(c-d) , **A99, 103.**
drilling said tool out of said well bore.*	Yes. McGowen, ¶¶ 6, 11(a) , **A99, 100-101.**	Yes. McGowen, ¶¶ 6, 15(a) , **A99, 103.**
	* Weatherford supervises their installation in wells. Burris Decl., ¶ 24, **A62.**	* BJ performs the related well services. Burris Decl., ¶ 24, **A62.**

BJ PYTHON™ COMPOSITE BRIDGE PLUG*

TOOLS

Product Information



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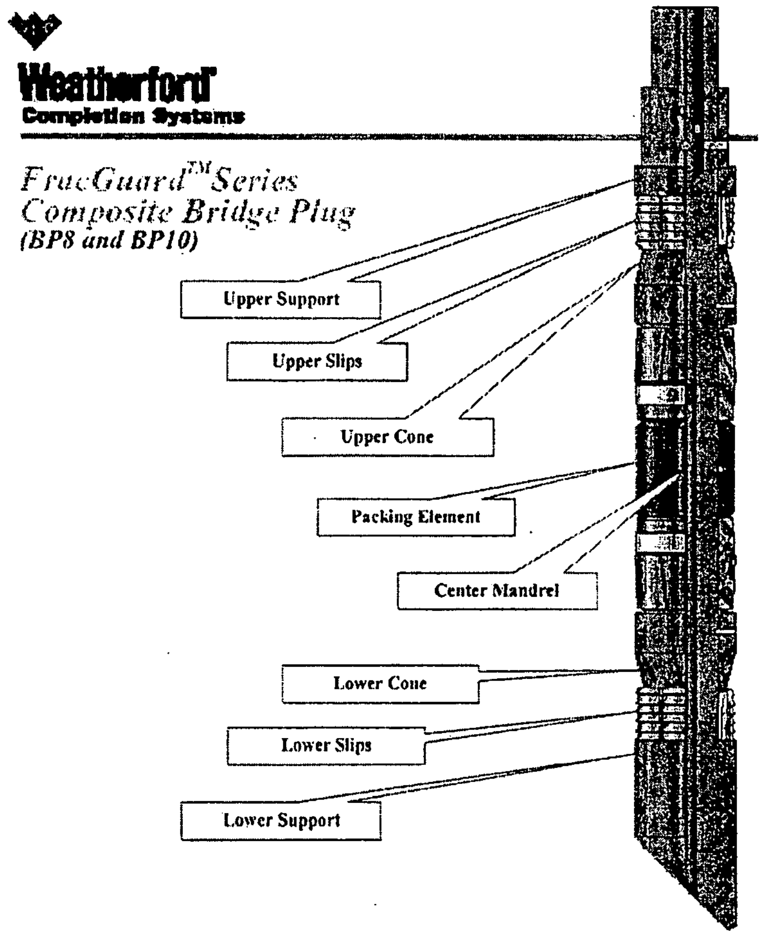

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US Patent # 5,271,468
Claim 30

30. A downhole apparatus for use in a well bore, said apparatus comprising:
a center mandrel made of a non-metallic material; and
slip means disposed on said mandrel for grippingly engaging said well bore when in a set position. **A16-17.**

'468 Patent, Claim 30	Weatherford's "FracGuard" composite bridge plug and frac plug	BJ's "Python" composite bridge plug
A downhole apparatus for use in a well bore, said apparatus comprising:	Yes. McGowen, ¶¶ 3, 5, **A98-99.**	Yes. McGowen, ¶¶ 4, 5, **A99.**
a center mandrel made of a non-metallic material; and	Yes. McGowen, ¶¶ 6, 11(b) , **A99-101.**	Yes. McGowen, ¶¶ 6, 15(b) , **A99, 103.**
slip means disposed on said mandrel for grippingly engaging said well bore when in a set position.	Yes, two slip assemblies, each including slips, a cone for wedging the slips, and a support structure for the slips on the opposite side of the cone. McGowen, ¶ 11(d) , **A100-101.**	Yes, two slip assemblies, each including slips, a cone for wedging the slips, and a support structure for the slips on the opposite side of the cone. McGowen, ¶ 15(d) , **A103.**

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US Patent #5,224,540

Claims 1-3

1. A downhole apparatus for use in a well bore, said apparatus comprising:
   a center mandrel; and
   slip means disposed on said mandrel for grippingly engaging said well bore when in a set position, said slip means being at least partially made of a non-metallic material.

2. The apparatus of claim 1 characterized as a packing apparatus and further comprising packing means disposed on said mandrel for sealingly engaging said well bore when in a set position.

3. The apparatus of claim 2 wherein said slip means is an upper slip means disposed above said packing means and further comprising a lower slip means disposed below said packing means, said lower slip means being at least partially made of a non-metallic material. **A 36.**

540 Patent, Claim 3 (which is dependent on claims 1-2)	Weatherford's "FracGuard" composite bridge plug / frac plug	BJ's "Python" composite bridge plug
From Claim 1:		
A downhole apparatus for use in a well bore, said apparatus comprising:	Yes. McGowen, ¶ 5, **A99.**	Yes. McGowen, ¶ 5, **A99**
a center mandrel;	Yes. McGowen, ¶ 11(b), **A100-101.**	Yes. McGowen, ¶ 15(b), **A103.**
slip means disposed on said mandrel for grippingly engaging said well bore when in a set position;	Yes, two slip assemblies, each including slips, a cone for wedging the slips, and a support structure for the slips on the opposite side of the cone. McGowen, ¶ 11(d), **A100-101.**	Yes, two slip assemblies, each including slips, a cone for wedging the slips, and a support structure for the slips on the opposite side of the cone. McGowen, ¶ 15(d), **A103.**
said slip means being at least partially made of a non-metallic material;	Yes, at least the cone and the slip support structure of the slip assemblies are made of a non-metallic material. McGowen, ¶ 11(e-f), **A100-102.**	Yes, at least the cone and the slip support structure of the slip assemblies are made of a non-metallic material. McGowen, ¶ 15(e-f), **A103-104.**
From Claim 2:		
the apparatus of claim 1 characterized as a packing apparatus; and	Yes, as a bridge plug or as a frac plug, which is a type of bridge plug. McGowen, ¶ 3, **A98-99.**	Yes, as a bridge plug. McGowen, ¶ 4, **A99.**
further comprising packing means disposed on said mandrel for sealingly engaging said well bore when in a set position;	Yes, a packing element on the tool designed to seal with the well bore. McGowen, ¶ 11(c), **A100-101.**	Yes, a packing element on the tool designed to seal with the well bore. McGowen, ¶ 15(c), **A103.**
From Claim 3:		
the apparatus of claim 2 wherein said slip means is an upper slip means disposed above said packing means and further comprising a lower slip means disposed below said packing means, said lower slip means being at least partially made of a non-metallic material.	Yes, the two slip assemblies are located above and below the packing element. McGowen, ¶ 11(d), **A100-101.**	Yes, the two slip assemblies are located above and below the packing element. McGowen, ¶ 15(d), **A103.**

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SPE 40052

New Composite Fracturing Plug Improves Efficiency in Coalbed Methane Completions

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This paper was prepared for presentation at the SPE Rocky Mountain Regional Meeting/Low Permeability Reservoirs Symposium and Exhibition held in Denver, Colorado, 5-8 April 1998.

Abstract

Success in coalbed methane (CBM) development projects can be attributed to efficient hydraulic fracturing of multiple coal seams and quick online gas production. Because the coal can be naturally fractured, friable, and somewhat plastic in nature, successful stimulation can be challenging.[1] Typical cased or openhole completion methods involve hydraulic fracturing of the coal seams. The seams may either be commingled and fractured together or isolated to perform staged fracturing treatments. Zonal isolation historically has been achieved when operators set inflatable plugs in the openhole or cast iron plugs in casing between stimulation intervals. Many operators use foamed fracturing fluids to enhance flowback and fracture closure after the initial treatment.

Inflatable packers have not been reliable in openhole completions, and this technology is developing at a slow pace in the industry. Difficulties also occur in either drilling or retrieving cast iron plugs used to isolate stimulation intervals in cased hole CBM completions. When multiple cast iron plugs are used in a single well, the difficulty in drilling out these plugs increases with the number of plugs. The increased difficulty is caused when the steel slips are drilled through and the remaining portion of the plugs drop on top of the undrilled plug or plugs left below. This remaining portion of the upper plug rotates freely on the fracturing sand and lower plug, increasing the drillout time on successive plugs. Retrievable plugs are difficult to remove because the fracturing sand left in the wellbore frequently enters the retrievable plug, creating releasing problems. Removal of cast iron plugs has taken as long as 8 days in some CBM completions.

A new composite epoxy-glass fracture plug was designed for use as an aid in the completion of multiple coal seams, allowing staged zonal treatment with flowback capabilities after treatment. The fracturing plug is made of an easily drillable, lightweight, composite material with no metal. The composite plug greatly reduces drilling time and drilling difficulties.

Case histories of more than 100 CBM wells that were completed with composite fracturing plugs are summarized in this paper. The new plug, combined with nitrogen-foam stimulation, improves completion efficiency and greatly reduces associated rig time in CBM operations. In addition, the new plug design greatly reduces the potential for downhole tool problems, including wellbore debris. Use of the new plug allows the operator to achieve wellstream production 30 days sooner than with previous plugs, allowing more rapid degasification of the coal.

Introduction

Coalbed methane (CBM) production has increased since production of the first gas from coal beds in Virginia was documented in 1948.[2] Given the marginal economics of many CBM production projects, optimizing the technology developed for specific CBM projects could mean the difference between success and failure of a project.[3] The fracturing plug described in this paper was developed for use in stimulation of mining and non-mining areas operated by CONSOL Coal Group (CONSOL); however, the primary CBM production is from mining areas.

CONSOL currently operates underground mines using longwall systems in southwestern Virginia. Coal production is obtained from the Pocahontas No. 3 (P3) seam at a depth of 1,500 to 2,500 ft from the surface. The gas content of this coal ranges from 450 to 650 scf/ton. The high gas content of the coal prompted CONSOL to initiate a vertical CBM drilling program in the early 1980's to degasify the P3 seam ahead of mine development to improve mine safety and productivity. Since that time, the scope and magnitude of CBM development have expanded. Nearly 170 wells have been drilled and stimulated since 1995. Completion has expanded from the minable seam to include multiple, thin coal seams overlying the P3 seam.

References at the end of the paper.

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The Original CBM Completion

The original completion is a modified combination of the multiple-seam, openhole completion originally used in the Black Warrior Basin[4] and a multiple-seam, perforated, cased-hole completion. The actual number of coal seams stimulated varies from location to location. The P3 seam is the thickest and most continuous seam ranging from 3 to 8 ft. There are 12 to 20 additional seams above the P3 ranging from less than 6 in. to several feet thick. Fig. 1 shows a stratigraphic column of the coalbeds overlaying the P3 seam.

Wells were completed using the process of drilling beyond the lowest coal, which was the P3 seam, and by setting casing from the surface to the top of this coal using a formation packer shoe. Casing sizes were typically 5 ½ in., but some 4 ½-in. casing was used. The workover rig that was used to install casing drilled out the formation packer shoe, prepared the well for fracture stimulation, and was moved off location.

The openhole zone was fractured first. The openhole completion of the P3 seam was implemented so that steel casing would not interfere with or compromise the safety of coal-mining operations. A cast iron drillable fracturing plug was then set in the casing just above the open hole. A fracturing ball was dropped to seat in the plug and seal off the openhole section from the next treatment interval. The ensuing stage was then perforated with four shots per foot and stimulated. Each cased-completion stage contained three to eight coal seams depending on their vertical location and thickness. The cased-hole completion process was repeated until all the coal seams had been treated. A typical well contained three or four stages (Fig. 2).

Staging the stimulation allowed more control of treating pressures and helped ensure that each interval received adequate treatment. Improved fracture diagnostics and control are two essential elements of successful stimulation in coal.[5] It has also been shown that coal-fracturing technology can be improved by reducing the tortuosity or pressure drop occurring across perforated intervals.[6] Stage fracturing is more likely to reduce perforation friction, a primary cause of tortuosity, because it is not necessary to limit the number of perforations in the well completion.

After all of the zones were treated, the well was immediately flowed back, allowing for adequate closure of the fractures and enhancing wellbore cleanup. A workover rig was subsequently moved in to location to drill the fracturing plugs and install tubing. Before drilling began, the hole was circulated to the upper plug to clean fracturing sand and fluid from the wellbore. The upper plug was usually set between 800 and 1,500 ft. Drill collars and a mill were used in the drillstring to drill up the plugs and to circulate out sand. At these shallow depths, however, the lack of drillstring weight made drilling through the upper plug difficult.

It usually took about 2 hours to drill through the slips of the top plug. When the mill drilled through the slips, the top plug would release and fall downhole, landing on the fracturing sand that was left on top of the next lower plug. The fracturing sand was circulated from the top of the next plug, but debris from the upper plug left in the wellbore made it difficult to circulate all the sand out of the wellbore cleanly.

After the slips had been drilled out, the top plug was free to rotate in the casing. Because the plug was made of cast iron, it had no way to anchor itself on the fracturing sand or on the top of the next plug. The plug continued to rotate when the mill came in contact with it, which greatly increased the drilling time and caused many delays in the drilling schedule.

The metal debris left from successive plugs fell to the bottom, causing further complications in the drilling process. Problems drilling out the metal plugs increased with the number of plugs that were run in a single well. Successive plugs took up to 12 hours to drill through, and delays of up to 8 days were experienced using cast iron drilling plugs. Fishing was sometimes necessary to recover mills and parts of drillstrings lost during the cleanout operation.

CONSOL considered other techniques for completion, including ball-and-baffle techniques and fiberglass casing. Ball-and-baffle techniques were not used in the mining area because the P3 seam was completed openhole. When the formation packer shoe was drilled before stimulation, the baffles would be destroyed during this process. Baffles would also create an internal diameter restriction that would limit the perforating-gun size. If baffles were used, the optimum perforating charges and standoff distance would have to be compromised. Smaller perforating guns would have to be used in the lower stages of the completion, increasing the perforation friction and the risk of screenout during hydraulic fracturing. In addition, baffles would have to be spaced out properly between the intervals to be treated, and their location would have to be selected before running casing into the well.

Fiberglass casing was tested. One joint of fiberglass was installed across the mined P3 seam. The drawback was that higher-than-normal treating pressures were encountered, possibly caused by cement invasion. In addition, the fiberglass shattered after perforation and stimulation. The fiberglass was, therefore, more prone to cause drilling tools and tubing to stick.

Retrievable plugs were also very difficult to remove because the fracturing sand complicated the retrieval process. Delays in drilling out plugs in the staged completion process resulted in delays in the entire project. To maximize project efficiency, CONSOL needed a new process to complete the CBM wells.

CBM Project Objectives

A fairly rapid degasification of the selected CBM site was critical to meet the overall economic objectives of the project. For the mining operations, it was critical that drilling of new wells continued on schedule to degasify the coal and prevent delays in the mining process. CONSOL personnel knew that plug drilling was costly and time consuming. When plug drilling was delayed, it was difficult to stay on schedule with the CBM completions without increasing the number of workover rigs for the project.

The operators' main objectives were to reduce the problems associated with drilling the cast iron plugs, decrease the high completion costs, and to improve the removal of wellbore debris. In addition, the operator wanted to continue to complete the CBM wells with staged completions and allow flowback of the wells as soon as possible after treatments. Many problems contributed to the high cost in each completion, including lengthy plug drilling times, poor circulation of drill cuttings/sand, stuck tools, and fishing operations.

A new way to isolate the coal seams for stimulation was necessary. A fracturing plug would have to be designed that was easy to drill out without damaging casing or becoming stuck during the process. The plug would have to allow for immediate flowback of the zone or zones below the plug and prevent fracturing balls from sealing off on the bottom side of the plug. Wireline-set tools that were more reliable to drill at shallow depths were preferred.

Development of a New Composite Fracturing Plug

A bridge plug design presented in 1994[7] was investigated. Benefits of the original design (Fig. 3) had been well accepted by the oil and gas industry and could also benefit coalbed methane operations. The exchange of ideas and the information provided by the field personnel, along with the review of existing bridge plug technology, led to the development of a new composite fracturing plug.

The numerous similarities between the bridge plug and the fracturing plug (Figs. 3 and 4) helped expedite the overall development time of the new design. The most significant challenge for designing the composite fracturing plug was the need for a completely redesigned inner mandrel. Unlike the bridge-plug mandrel, the fracturing-plug mandrel would need to have a completely unrestricted internal diameter (ID) to allow flowback through the fracturing plug after the fracturing treatment was complete. In addition to the open ID, the mandrel needed to incorporate a landing seat for the fracturing ball to rest on after the ball is placed or dropped on top of the tool. Another requirement of the new fracturing plug was to prevent fracturing balls from sealing on the bottom of upper plugs during flowback. This objective was accomplished by inserting a pin across the ID of the mandrel at the bottom of the plug. The pin allowed well fluids to flow through the tool and prevented fracturing balls from entering or sealing the ID from below.

Because the tool is of composite construction, the outer components of the fracturing plug must be attached to the inner mandrel by a series of composite pins and bonded connections. These pins provide the means to prevent the mandrel from being pumped out of the tool when exposed to the setting forces and hydraulic forces during pumping operations. With the ball needing to seal at the very top of the mandrel, the pins that would normally hold the tool together became a potential leak path for the hydraulic fracturing fluids.

The focus of the design for the inner mandrel was to develop a set of restraining pins that would hold the tool together and prevent fluid migration through the top of the tool at the pin locations. This objective was accomplished using a series of shorter pins that limited the depth of penetration into the mandrel. By keeping the pins as short as possible, the mandrel's cross-sectional thickness was increased, thereby improving the mandrel's performance. A series of tests was performed on three different prototype mandrels to establish the ideal pin configuration. The final design was tested at a pressure differential of 6,000 psi for 30 minutes to confirm mandrel integrity.

A design layout was generated to determine the size of fracturing ball that was needed to ensure that the ball could only land on the top of the mandrel and not become lodged between the top of the mandrel and the casing ID. Prototype testing in a vertical test chamber was conducted to simulate dropping the ball from the surface. In all the tests, the ball seated correctly on the top of the mandrel, and the new fracturing plug design (Fig. 4) was ready to field test.

The composite fracturing plug and the composite bridge plug were originally intended for use with the same wireline adapter kits. After the first composite fracturing plugs were run, it became evident that in some wells it would be better if the fracturing ball could be run in place (on top of the mandrel) instead of having to be dropped from the surface after the plug is set. Adapter kits were designed with a large recessed area to allow the fracturing ball to run in with the fracturing plug (Fig. 5).

A clear understanding of the kind of tool that was needed and the ability to provide accurate information to the design team expedited the development time of the new plug. The total elapsed time from the initial request to the final delivered product was less than 1 month. The prototypes were tested to provide quality assurance under fracturing conditions and were distributed to the wellsite for field testing on an actual CBM completion. The new composite fracturing plugs were tested without failures and were put into production. The first tools arrived less than 3 weeks after the prototype testing was completed.

Advantages of the New Composite Fracturing Plug

The new composite fracturing plug combines the benefits of cast iron fracturing plugs and composite bridge plugs (Table 1). Drilling is accomplished using a tri-cone bit rather than a mill. Because only composite material is used in the plug, drilling speed (rev/min), string weight, and circulation rate can be varied to easily identify the best drilling performance with the composite plugs. Both conventional drillstrings and coiled tubing have proved successful in drilling the plugs. In other projects, even cable-tool drillstrings have proved successful in removing the composite plugs.

The body and main components of the composite fracturing plug are made of composite plastic material. The slips have ceramic buttons. The sealing elements and the O-rings used in

the plug are of the same rubber compounds used in standard bridge plugs and packers. The tools can be run and set on electric wireline using a special setting kit, on slickline using a downhole power unit, on a conventional tubing string, or on coiled tubing. In the wireline-setting method, the steel shear pins used in the setting kit are the only metal parts used in the plug assembly. The electric wireline setting method was chosen for this CBM project.

Another advantage of the new design is that the fracturing balls can be run in place rather than dropped separately before stimulation. The fracturing plugs maintain the same pressure and temperature ratings as the original bridge plug design. The plugs are rated for 5,000 psi maximum differential pressure and 250°F. Fracturing plugs are currently available to run in 4 ½- and 5 ½-in. casing. The flow-through design and the use of fracturing balls allow each stage to flow back through the plug, improving cleanup and enhancing fracture closure.

The composite bridge plug was designed to wedge into the top of a plug set below it. The fracturing plug incorporated this design. When the top slips are drilled through, the plug drops or is pushed to the bottom where it usually rests on fracturing sand. While the sand is circulated off the bottom, the knife-edge taper on the bottom of the upper plug body wedges into the sand and eventually into the top of the other plug (Fig. 6). This design prevents rotation of the released upper plug body during the drillout process.

During the drilling phase, the small composite plug cuttings float in the circulation fluid and return to the surface. Larger pieces of the plug that fall to the bottom are quickly ground and cut into smaller pieces that are flushed to the surface in the circulation returns. Much less string weight is needed to drill and break up the composite material. The composite plugs drill out in less than 30 minutes on average and in some cases in less than 10 minutes, depending on the drilling process. This condition leads to quicker plug removal than with cast iron drillable plugs. Rapid wellbore cleanup also results in lower drilling costs.

The composite material caused little or no damage to the tri-cone bits in contrast to the mill damage in the original completion, resulting in lower bit cost for the overall project. The composite plugs improved the cutting returns and produced better circulation, thus reducing formation damage and eliminating wellbore debris that delayed drilling.

The New Completion Procedure

As in the original completion, the well is drilled beyond the lowest zone (the P3 seam) and casing is set from the surface to the top of this zone using a formation packer shoe. The bottom zone is still completed openhole. Typically, 5 ½-in. casing is used to complete the upper zones. These seams are still completed behind the pipe and are perforated using four shots per foot. Seams behind the pipe were grouped together for stimulation in stages containing one to five actual coal seams as described earlier. The stimulation procedure would be similar to those performed in the original completion with three or four stages selected.

The advantage of the new completion procedure involves the use of the composite fracturing plug and the improved drilling program (Fig. 7). In the new process, the lower openhole zone is fractured first. A composite fracturing plug is made up on a wireline adapter kit (Fig. 8). An electric wireline unit is used to set the fracturing plug in the casing above the openhole zone. A fracturing ball is either run in place or dropped on top of the plug before the next stage is stimulated. The wireline is then used to perforate the second stage, and the second stage is fractured. This process is repeated for the third and fourth stages. The commingled zones are flowed back to ensure fracture closure and to clean treatment fluids from the well.

A workover rig is then used to circulate the hole clean and to drill out the plugs. A typical drillstring used in this CBM project would consist of tubing or drill pipe, some drill collars to add weight, and a tri-cone bit (Fig. 9). Actual drilling depends on depth, string weight, drill speed, and circulation rates. Two important factors observed in drilling composite plugs are that there is little (if any) damage to the drill bit and that the composite plugs drill much faster than metal plugs.

The first plug is drilled out in 10 to 30 minutes, depending on the depth and amount of fracturing sand left in the wellbore. It is typical to circulate out sand before drilling the next plug. However, this step has been modified successfully by experienced drilling contractors and may be done in conjunction with drilling the next plug. Additional plugs are drilled up in about 30 minutes, including the time to drill through the lower body of the upper plug. When the last plug is drilled through and releases, it is chased to the bottom and completely drilled out. The hole is circulated clean and is ready to run tubing and pumping equipment.

Case Histories: Field Testing and Drilling

Less than 1 month after initial work on the plug began, three plugs of the first model were manufactured and delivered to the field site for testing on a CBM pilot well. One openhole stage and three cased-hole stages were completed using the new composite fracturing plug. The plugs were set in 5 ½-in. 15.5-lb/ft. casing using a wireline adapter kit. After the openhole P3 seam was fractured, a fracturing plug was set in the casing. A fracturing ball was then dropped, allowing the next cased-hole stage to be performed. The second stage was completed and the process was repeated for the third and fourth stages. The fracturing balls sealed without incident on all stages.

To drill out the plugs, a pole-rig workover unit with a power swivel was used. Approximately 93 ft of 2 ⁷/₈-in. drill collars were used with the 2-³/₈ in. workstring. The total string weight was less than 8,000 lb to drill out the first plug. A medium/hard tri-cone bit was used with 8.3 lb/gal fluid. Sand was washed off the top plug, which drilled out and released in 30 minutes. A drill speed

of 80 rev/min and a pump rate of 1 bbl/min was used on the first plug. The hole was circulated clean, and the remainder of the first plug fell to the bottom. It took another 45 minutes to clean the lower portion of the first plug and fracturing sand off the second plug. This procedure was performed at a drill speed of 100 rev/min and a pump rate of 1.5 bbl/min. Using the same drill speed and circulation rate, the second plug drilled out in only 18 minutes. The remainder of the second plug along with fracturing sand was cleaned out of the wellbore, and the third plug was drilled out in 15 minutes.

Based on the successful plug drilling of the pilot well, the fracturing plugs were put into full production for the Virginia CBM project. In this project, plugs were set from 650 to 2,400 ft vertical depth. The plugs were drilled using a tri-cone bit at a rate of 80 to 110 rev/min. Two or three drill collars were used to achieve 6,500 to 10,000 lb of total drillstring weight. Circulation was maintained at a pump rate of 2 to 3 bbl/min during the plug-drilling phase. To date, over 300 plugs have been used successfully with no setting or drilling problems. Both 5 ½- and 4 ½-in. plugs are now available for stage fracturing. The fracturing balls can be run in place or dropped depending on operator preference.

Economic Value of the New Completion Process

There are many economic considerations in evaluating a coalbed methane project. Rig and completion costs are a major concern to the project. Equipment and personnel expense in field operations are also considered. Unexpected delays in CBM completions and metal debris left in wells from drillouts can result in costly recovery work. Delays in the well work often carry over to delays in the mining process itself. Considering today's economics of methane gas production, lengthy well completions delay wellstream gas revenues and cause a decline in gas reserves from mining area wells.

Rig cost was reduced by an average of 56% during completion phases of this project when the new composite fracturing plug was used instead of cast iron drillable plugs. This cost reduction still holds true after nearly 100 completions. Supervisory time on location was also reduced by 70%. Water used in drilling was reduced by $300 per completion. These completion cost savings offset the increased cost of the composite plug and resulted in a savings of $1,830 per CBM well.

In addition to the completion cost, the cost of the mill bits used to drill out the cast iron plugs in the original completion averaged $1,000 per completion. Mill life averaged 3.5 cast iron plugs per mill vs. 8.0 composite fracturing plugs per tri-cone bit (Table 2). The mills were badly worn and had to be replaced. There was little wear using the composite fracturing plugs, and change-outs of tri-cone bits were made only as a precaution during a normal pipe trip. For every 100 wells in the project, mill cost averaged $85,700. The cost of a tri-cone bit is only $225, and no change-out trip is required. Over the same 100-well program, the bit cost to drill out composite plugs averages only $8,500. This produces a bit savings of $77,200 in a 100-well program (Fig. 11) or $772/well.

Conclusions

Many engineering and geologic factors contribute to the productivity of coalbed methane wells.[8] The U.S. Environmental Protection Agency estimates that by 2010, an additional 100 Bcf/year of coalbed gas could be recovered in the United States alone if existing technology was fully employed.[9] A successful completion program depends on selecting the most appropriate stimulation and completion techniques for a specific CBM project. Staged stimulation treatments have proved to be a very effective way to optimize gas production in this project.

The new composite fracturing-plug design has provided CBM projects with a more efficient and cost-effective way to stage stimulation treatments. The staged treatments allow for better removal of methane gas through well completions. Staging also provides more reliability in treating pressures and optimizes the hydraulic fracture design in the coal seams. Fracturing treatments can be more closely engineered through staging techniques, and the results of these treatments can be modeled more effectively using fracturing and reservoir simulators.

The flowback capabilities of the new process allow forced closure and better cleanup after fracturing coal. The improvement in hydraulic fracturing in this CBM project means more production of gas and improved mining conditions through the P3 seam. The shorter completion time improves degassing the mine, reduces methane downtime, and results in a better net present value for the coal gas assets.

Acknowledgments

The authors thank the management and staff of CONSOL, Inc., and Halliburton Energy Services, Inc., for permission to publish this paper. Additional thanks are extended to the CONSOL and Halliburton field staff and business development personnel for their critical efforts developing this project.

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9. Schultz, K.: "U.S. Environmental Protection Agency's Promotion of Coalbed Methane," paper 9763 presented at the 1997 International Coalbed Methane Symposium, Tuscaloosa, AL, May 12-16, 1997, 93-104.

Table 1—Plug Comparison

Advantages	Cast Iron Plugs	Composite Bridge Plug	New Frac Plug
Allows Flowback	X		X
Easy to Drill		X	X
Inexpensive to Complete Wells		X	X
Reliable		X	X

Table 2—Bit Cost Comparison

	Original Completion	New Completion
Plug Type	Cast iron	Composite bridge material (CBM)
Drillout Method	Mill	Tri-cone bit
Cost Per Bit/Mill	$1,000	$225
Average Number of Plugs Per Changeout	3.5 per mill	8 per bit
Amount of Wear	Heavy	Light

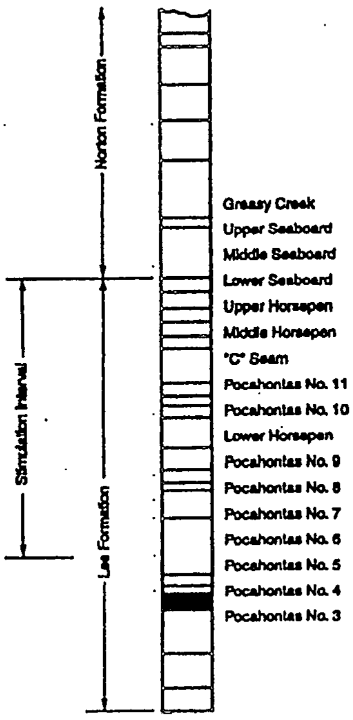

Fig. 1—Stratigraphic column showing coalbeds in Buchanan County, Virginia.

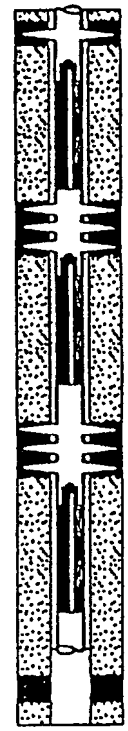

Fig. 2—Original completion with three or four stages.

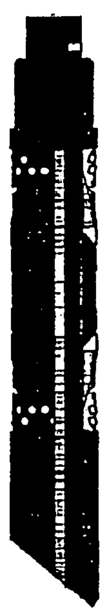

Fig. 3—Original plug design for composite bridge plug.

Fig. 4—Composite modified fracturing plug.

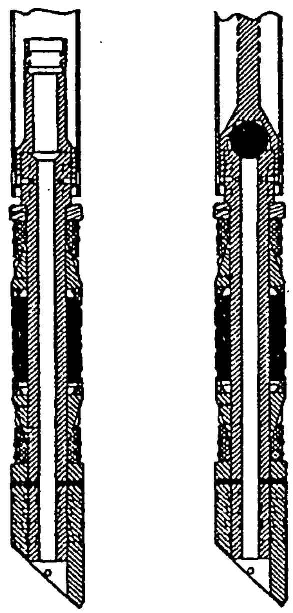

Fig. 5—Ball-in-place modification.

Fig. 6—Wedge design.

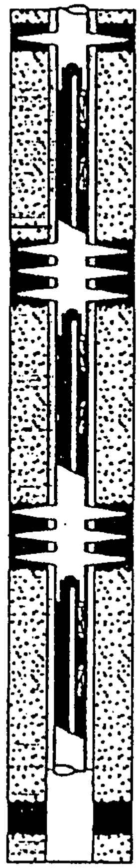

Fig. 7—New CBM completion procedure.

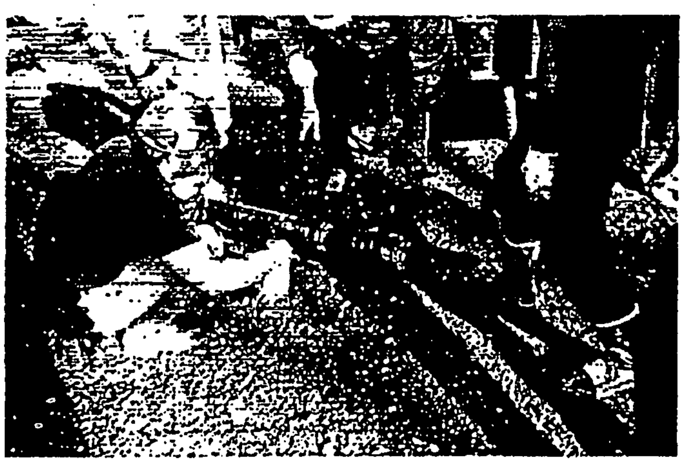

Fig. 8—Wireline set system.

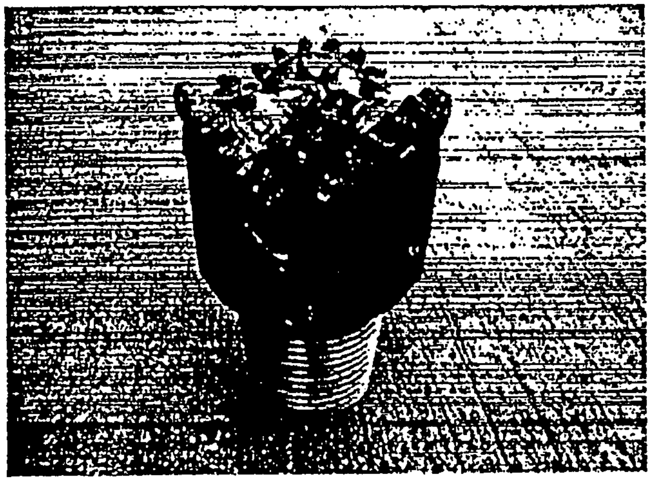

Fig. 9—Tri-cone bit.

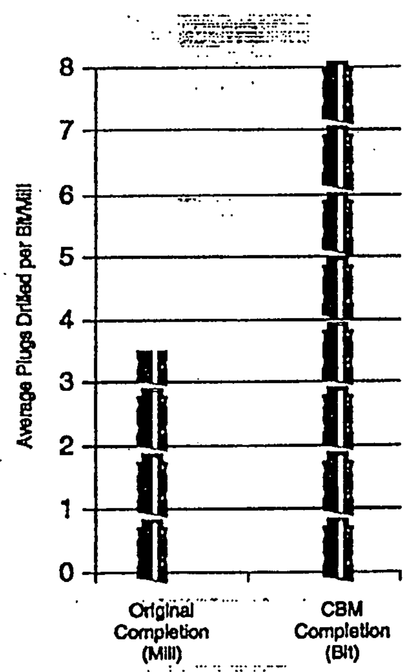

Fig. 10—Comparison of cast iron plugs drilled with mill and composite plug drilled with bit.

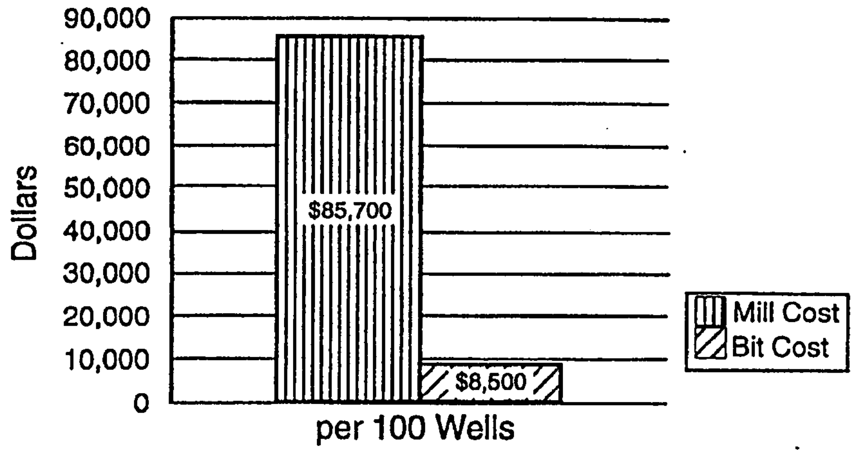

Fig. 11—Comparison of mill cost and bit cost showing a $77,200 cost savings per 100 wells.

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